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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application of Central Valley Gas Storage, LLC (U915G), AGL Resources Inc. and The Southern Company for Expedited *Ex Parte* Authorization to Transfer Ownership of Central Valley Gas Storage, LLC to The Southern Company.	A1511011 Application _________ (Filed November 9, 2015)

JOINT APPLICATION FOR TRANSFER OF OWNERSHIP
OF CENTRAL VALLEY GAS STORAGE, LLC (U915G)
PURSUANT TO PUBLIC UTILITIES CODE SECTION 854(a)

Pursuant to Section 854(a) of the California Public Utilities Code and Article 2 and Rule 3.6 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure ("Rules"), Central Valley Gas Storage, LLC (U915G) ("Central Valley"), AGL Resources Inc. ("AGLR") and The Southern Company ("Southern Company") (collectively the "Joint Applicants") request expedited *ex parte* authorization to transfer indirect ownership of Central Valley to Southern Company from Central Valley's ultimate parent, AGLR, which will become a wholly owned subsidiary of Southern Company pursuant to an August 23, 2015 Agreement and Plan of Merger ("Merger Agreement"). As set forth in detail, below, Joint Applicants have satisfied all of the requirements for approval of the transfer of ownership, and respectfully request that the Commission issue an order approving the ownership transfer as requested herein.

I. OVERVIEW

This Application seeks Commission authorization pursuant to Section 854(a) of the Code for the transfer of indirect ownership of Central Valley to Southern Company.1/ Specifically, on

1/ Sections 854(b)-(c) of the California Public Utilities Code are not applicable here because neither AGLR, Southern Company, nor any of either company's affiliates has gross annual California revenues that

August 23, 2015, AGLR and Southern Company executed the Merger Agreement pursuant to which AGLR will become a wholly owned subsidiary of Southern Company. Central Valley is an indirect subsidiary of AGLR, and hence, upon approval of the merger, Central Valley will become an indirect subsidiary of Southern Company. Accordingly, Central Valley's indirect change in ownership is subject to the Commission's approval of this Application.

Notwithstanding the indirect change in ownership, Central Valley will continue to operate as an independent natural gas storage provider subject to the jurisdiction of the Commission. In addition, the transaction will not result in the transfer of any certificates, assets or customers of Central Valley. Central Valley will continue to be bound by all of the terms and conditions prescribed by the Commission in its decision granting Central Valley a Certificate of Public Convenience and Necessity ("CPCN") for construction and operation of its natural gas storage facility.2/

As detailed in this Application, Joint Applicants have met all the requirements for approval of a transfer of ownership. Specifically, in Section II, Joint Applicants have provided detailed descriptions of the various companies involved in the transaction. In Section III, Joint Applicants have described the transaction in detail. In Section IV, Joint Applicants have demonstrated that the transaction meets the public interest standard under § 854 of the Code. In Section V, Joint Applicants have shown compliance with the California Environmental Quality Act ("CEQA") (Public Resources Code § 21000 *et seq.*) by detailing reasons why the transfer of ownership is not a "project" under CEQA and, thus, not subject to review under that statute. In Sections VI and VII, Joint Applicants have requested expedited *ex parte* approval of the

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exceed $500 million.

2/ Decision Granting Application for A Certificate of Public Convenience and Necessity to Construct and Operate a Gas Storage Facility, D.10-10-001, No. A.09-08-008 (CPUC Oct. 14, 2010).

transaction and provided all requisite information required under Rule 2.1(c) of the Commission's Rules of Practice and Procedure.

Based on this showing, Joint Applicants respectfully request the Commission to approve the transfer of ownership requested in this Application.

II. DESCRIPTION OF JOINT APPLICANTS

A. Central Valley Gas Storage, LLC and AGL Resources Inc.

Central Valley is a Delaware limited liability company with licenses to do business in California and Illinois. Its principal place of business is Lisle, Illinois.

Central Valley is a separate legal entity that is an indirect subsidiary of AGLR, which is a Georgia corporation headquartered in Atlanta, Georgia. AGLR's principal business is the distribution of natural gas through public utility operating companies in seven states: Nicor Gas Company in Illinois; Atlanta Gas Light Company in Georgia; Chattanooga Gas Company in Tennessee; Elizabethtown Gas in New Jersey; Elkton Gas in Maryland; Florida City Gas in Florida; and Virginia Natural Gas Company in Virginia. AGLR's seven utility companies currently serve nearly 4.5 million end-use customers. They are each state-regulated local gas distribution utilities that construct, operate, and maintain intrastate natural gas pipelines and distribution facilities. Through its non-utility subsidiaries, AGLR also is involved in several other businesses, including: retail natural gas marketing to end-use customers; natural gas asset management and related logistics activities for certain of its utilities and nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets.

With respect to market based-rate storage assets, in addition to Central Valley, AGLR owns two facilities currently in operation: Golden Triangle Storage, Inc., a salt cavern storage facility in Texas; and Jefferson Island Storage & Hub, L.L.C., a salt cavern storage facility located in Louisiana.

Other than Central Valley, the AGLR corporate family does not have any businesses based in California or own any assets on the West Coast.

On October 14, 2010, the Commission granted Central Valley's application for a CPCN authorizing the construction and operation of an underground natural gas storage facility in Colusa County.3/ Central Valley is comprised of (1) an 11 Bcf underground natural gas storage field ("Storage Field") within the Princeton Gas Field, (2) a compressor station and dehydration units, (3) a remote well pad site, (4) injection/withdrawal, observation, and salt water disposal wells, (5) a metering station, and (6) a natural gas pipeline extending approximately 14.7 miles from the Storage Field to an interconnection with the metering station and PG&E's Line 400/401 gas transmission pipeline. Central Valley commenced commercial operation in March 2012.

As the Commission is aware, in 2011 the Commission previously granted expedited *ex parte* authorization for the indirect transfer of ownership of Central Valley from Nicor, Inc. ("Nicor") to AGLR.4/ No interested parties protested Central Valley's application. In approving the transfer of ownership, the Commission also concluded that the underlying transactions were exempt from CEQA, and thus required no additional environmental review.

The current management team of Central Valley is as follows:

CEO	Peter I. Tumminello
President	Stephen J. Cittadine

3/ *Id.*

4/ Decision Approving Change in Ownership and Control of Central Valley Gas Storage, LLC D.11-05-030, No. A.11-01-021 (CPUC May 26, 2011).

Executive Vice President and General Counsel	Paul R. Shlanta
Senior Vice President and CFO	Brian K. Little
Vice President, Tax	Grace A. Kolvereid
Vice President, Gas Operations	Charles A. Rawson III
Vice President, Storage and Peaking Operations	Timothy J. Hermann
Vice President, Risk Control	James J. Goerig
Treasurer	L. Stephen Cave
Corporate Secretary	Jeffrey P. Brown
Assistant Corporate Secretary	Dat T. Tran
Assistant Corporate Secretary	Barbara P. Christopher

B. Southern Company

Southern Company is an Atlanta-based public utility holding company currently providing electric utility service through four state-regulated operating companies in Alabama, Florida, Georgia and Mississippi. Southern Company brands are known for excellent customer service, high reliability and affordable prices. The first holding company in Southern Company's lineage dates to 1912. Currently, Southern Company is the parent of Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company. Approximately 90 percent of Southern Company's net income comes from its state-regulated electric utility subsidiaries. Southern Company's other subsidiaries include Southern Power, a wholesale energy provider, and Southern Telecom and SouthernLINC Wireless, which provide fiber optics and wireless communications. Today, Southern Company's state-regulated utilities serve more than 4.5 million customers throughout 120,000 square miles of regulated service territory.

Southern Company recognizes that public utilities have unique obligations and responsibilities to their customers. Consequently, Southern Company places the customers and communities that it serves at the center of everything it does. That philosophy is reflected in Southern Company's commitment to providing safe, reliable, and affordable service. It also informs Southern Company's efforts in the areas of economic development, business diversity, and community involvement. This philosophy is one of the reasons that Southern Company is one of only two utilities listed in Fortune's annual "World's Most Admired Electric and Gas Utility" rankings for each of the last five years.

Southern Company's organizational philosophy is founded on the strength, independence, and local management of its operating companies. Understanding and being responsive to the particular needs of each service territory is critical to providing first-rate utility service. Therefore, Southern Company's operating subsidiaries each have their own executive management teams that are responsible for each subsidiary's operations. These responsibilities extend beyond day-to-day operations and include responsibility for key decisions, such as long-term resource planning. Southern Company will apply the same organizational approach to AGLR and Central Valley.

C. Designated Contacts for Applicants

The designated contacts for questions concerning this Application and service of pleadings are:

For Central Valley:

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D. Certificates of Formation and Financial Statements

A copy of Central Valley's Certificate of Formation is attached hereto as Exhibit 1. Central Valley is qualified to do business in the State of California. A copy of its Certificate of Registration to do business in California issued by the Secretary of State is attached hereto as Exhibit 2.

The most recent Annual Report to Shareholders, proxy statement, and financial statements from the Annual Report on Form 10-K for AGLR are attached as Exhibit 3, Exhibit 4, and Exhibit 5, respectively. The most recent Annual Report to shareholders, proxy statement, and financial statements from the Annual Report on Form 10-K for Southern are attached as Exhibit 6, Exhibit 7, and Exhibit 8, respectively.

III. DESCRIPTION OF THE MERGER

Southern Company, AMS Corp.5/ and AGLR have entered into the Merger Agreement, a copy of which is submitted with this Application as Exhibit 9. Pursuant to the terms of the Merger Agreement, subsequent to obtaining all applicable regulatory approvals, Southern Company will acquire AGLR by purchasing its common stock at a price of $66 per share. To finance this purchase, Southern Company plans to issue approximately $3 billion in new Southern Company equity between now and the end of 2019 and to issue approximately $5 billion in new debt at the Southern Company level.

Upon consummation of the merger (the "Closing"), AMS Corp. will be merged into AGLR and Southern Company will hold all of the common stock of AGLR. Although AGLR will continue to exist as a distinct corporate entity, it will no longer be a publicly

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5/ AMS Corp., a Georgia corporation, is a wholly-owned subsidiary of Southern Company that was formed for the purpose of acquiring AGLR in the merger. AMS Corp. will cease to exist as a separate legal entity upon completion of the merger.

traded company. Instead, after the Closing, AGLR will continue to exist as a wholly-owned first-tier corporate subsidiary of Southern Company, and Central Valley's position within AGLR's corporate structure remains unchanged. A diagram showing the corporate organization structure both before and after the proposed transaction is shown in Exhibit 10.

Central Valley will retain its current name, its corporate form as a limited liability company, its principal place of business in Lisle, Illinois and its office on site in Colusa, California. Further, Central Valley will continue to operate as a California public utility, subject to the Commission's jurisdiction and applicable California law and regulations. After the transaction is completed, Central Valley will continue to hold the CPCN for its Storage Facility issued by the Commission in D.10-10-001 and will continue to be responsible for operating and maintaining safety and environmental oversight under its CPCN.

IV. THE PROPOSED TRANSFER OF CONTROL IS IN THE PUBLIC INTEREST

Public Utilities Code § 854(a) requires Commission authorization before a company may "merge, acquire, or control either directly or indirectly any public utility organized and doing business in this state."6/ The Commission has broad discretion to determine whether a particular transaction is in the public interest and should be approved under Section 854(a). Although there have been some cases where the Commission considered a different standard, in recent cases, the Commission has made clear that the appropriate standard to determine if a transfer of ownership should be approved is whether the transaction will or will not be "adverse to the public interest."7/ Accordingly, Joint Applicants request that the

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6/ Cal. Pub. Util. Code § 854(a) (2010). Sections 854(b) and (c) of the California Public Utilities Code do not apply to this application because none of the entities involved have gross annual California revenues exceeding $500,000,000.

7/ *See, e.g.,* Decision Approving Ownership Transfer of Lodi Gas Storage L.L.C., D.14-12-013, A.14-09-001 (CPUC Dec. 4, 2014); Decision Approving Change in Ownership and Control of Central Valley Gas

Commission apply these same standards to this Joint Application, consistent with prior decisions regarding the change in ownership of independent gas storage providers, including the prior transfer of ownership of Central Valley to AGLR.

Under this standard, the indirect transfer of ownership is clearly in the public interest. There will be no adverse effect on the public interest because the transfer will not result in any change to the services provided by Central Valley, or to the rates or terms and conditions under which services are provided. Since commencement of service, Central Valley has provided unbundled storage services to the public at market-based rates as approved in D.10-10-001, subject to all terms and conditions of Central Valley's CPCN. In this regard, the Commission required Central Valley to maintain \$50 million of general liability insurance per occurrence and in the aggregate (with certain inflation adjustments) and to obtain the insurance either directly or through Nicor.8/ AGLR later assumed this responsibility from Nicor, pursuant to the Commission's approval of Central Valley's transfer of ownership from Nicor to AGLR.9/ Under the terms of the proposed transaction, Southern Company will replace AGLR as Central Valley's ultimate parent and, as such, Southern Company will commit to, and be bound by, this condition.

In addition, Central Valley represented in its CPCN application that:

> (1) Neither Nicor, nor any of its affiliates, conducts any business or owns any assets, besides Central Valley, in the state of California or on the West Coast with the exception of a very limited amount of business conducted by Nicor Services.10/

Storage, LLC D.11-05-030, No. A.11-01-021 (CPUC May 26, 2011); Opinion Approving Transfer of 100% Interest in Lodi Gas Storage, LLC to Buckeye Gas Storage LLC, D.08-01-018, No. A.07-07-025 (CPUC July 27, 2007); Opinion Approving, With Conditions, Transfer of Control and Related Financing, and Exempting Ancillary Transaction from Public Utilities Code Section 852 Pursuant to Section 583(b), D.06-11-019 at 14, No. A.06-05-033 (CPUC Nov. 9, 2006) (*In re Joint Application of Wild Goose Storage Inc., et al.*); Opinion Approving Transfer of 50% Interest in Lodi Holdings, LLC, D.05-12-007, No. A.05-08-031 (CPUC Dec. 1, 2005).

8/ D.10-10-001 at 33-34.

9/ D.11-05-030 at 6-7.

10/ Application of Central Valley Gas Storage, LLC for a Certificate of Public Convenience and

> (2) Neither Central Valley nor any of its affiliates has any contractual rights or obligations related to the gas storage industry in California or on the West Coast (other than the fact that Central Valley itself has since entered into contracts with California customers).11/

The proposed merger will not impact these representations or the conclusion that Central Valley and its affiliates lack market power in California and on the West Coast given that neither Southern Company nor any of its affiliates: (a) owns any gas storage or pipeline assets in California or the West Coast; (b) holds any firm natural gas storage capacity rights in California or the West Coast; or (c) holds any natural gas transportation capacity in California.12/. Since Central Valley's CPCN application filing and subsequent transfer of ownership to AGLR, Central Valley affiliate Sequent Energy Management ("Sequent"), a natural gas marketer operating nationwide, has entered into a small number of gas storage and gas transportation transactions on the West Coast.13/ These transactions do not provide Sequent, Central Valley or any other affiliates with control of gas storage assets amounting to market power. In light of the foregoing, the merger will have no significant impact on competition in the relevant marketplace.

Additionally, Central Valley will significantly benefit from Southern Company's combination with AGLR. The merger will combine two companies with complementary

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Necessity for Construction and Operation of Natural Gas Storage Facilities at 5, D.10-10-001, No. A-09-08-008 (CPUC Aug. 5, 2009).

11/ *Id.* at 34.

12/ The only assets that the Southern Company holds in California are solar assets, which are identified in Exhibit 11. AGLR notes that Nicor Services no longer conducts any business in California.

13 Sequent has two storage contracts in California, one at PG&E's Citygate and the other at SoCalGas' Citygate. Both are for 2 Bcf MSQ, expiring March 31, 2016. Sequent also has a storage services master agreement with Central Valley but does not currently have any active storage transactions there. Along with being active in the daily interruptible transmission capacity market on PG&E's system, Sequent also holds transportation capacity on Kern River Gas Transmission with firm deliveries into SoCalGas' system at Kramer and Wheeler Ridge points, expiring April 30, 2018. In addition, Sequent delivers landfill gas into California.

expertise and skill sets and will create a combined company with a more geographically diverse footprint. The overall size of the combined company and Southern Company's strong financial position will provide AGLR and Central Valley with benefits that ultimately will inure to the benefit of customers. Southern Company has investment-grade credit ratings, substantial financial resources, and a consistent track record of maintaining the financial strength of its locally-operated and regulated subsidiaries. In this regard, rating agencies have already reviewed the terms of the merger, as announced on August 24, 2015, and considered the likely effects of the merger on credit quality. Among other things, those rating agencies cited the benefits that AGLR will realize from the enhanced scale and financial flexibility resulting from the merger. Post-Closing, the combined company will have the financial resources to enable Central Valley to continue to meet all of its capital needs and to continue providing provide safe and reliable services to California customers.

Finally, the merger will have no adverse impact on safety. Post-Closing, Central Valley will continue to function as an independent natural gas storage provider and the existing operating staff will continue to oversee day-to-day activities. Operations will remain consistent with current safety standards and Central Valley's Revised Natural Gas System Operator Safety Plan.

In short, Joint Applicants submit that the indirect change of ownership will have no negative consequences to the public interest and therefore should be promptly approved.

V. CEQA COMPLIANCE

The proposed transfer of ownership is not a "project" within the meaning of CEQA and, as a result, CEQA does not apply to this Application. Accordingly, pursuant to Rule 2.4 of the Commission's Rules, the Joints Applicants request that the Commission determine that the proposed transfer of ownership transaction is not a "project" within the meaning of CEQA, Public Resources Code, Section 21000, *et. seq.*

CEQA applies only to "projects." Projects subject to CEQA are defined as any "activity which may cause either a direct physical change to the environment, or reasonably foreseeable indirect physical change in the environment."14/ CEQA does not apply where the proposed "activity will not result in any direct or reasonably foreseeable indirect physical change in the environment."15/ The CEQA Guidelines provide for an exemption "[w]here it can be seen with certainty that there is no possibility that the proposed activity in question may have a significant effect on the environment."16/

In its issuance of a CPCN for the Central Valley Project, the Commission conducted a full environmental review under CEQA and adopted a Mitigated Negative Declaration.17/ Upon approval of this Application by the Commission, Central Valley will be obligated to continue operating its storage facility in the same manner as approved by the Commission in D.10-10-001, and Central Valley will continue to comply with all environmental conditions imposed in its CPCN and the required mitigation plan.

The transaction at issue in this Application simply involves the indirect transfer of ownership of Central Valley as a result of the proposed merger. Approval of such transfer of ownership will not result in any direct or indirect change in the environment or any change in Central Valley's previously reviewed and approved construction and operation criteria for its

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14/ *See* Cal. Pub. Res. Code §§ 21065, 21080(a) (2010).
15/ Cal. Code Regs. 14, § 15060(c)(2) (2010).
16/ *Id.* § 15061(b)(3).
17/ D.10-10-001 at 43-47.

storage facility. The Commission has previously held that such transfers of control either do not constitute projects within the meaning of CEQA or qualify for an exemption from CEQA.18/

VI. REQUEST FOR EXPEDITED AND *EX PARTE* TREATMENT

The Joint Applicants request that the Commission approve this application on an expedited and *ex parte* basis. It is in the public interest that the Commission process this Application as expeditiously as possible to avoid any undue delay in the transition of the ownership of Central Valley. In this regard, Central Valley is requesting that a Proposed Initial Decision be issued in January 2016 so that a Final Commission Decision can be issued no later than February 2016.

In order to expedite the processing of this Application, Joint Applicants are requesting this matter be handled on an *ex parte* basis, consistent with similar applications for change in control of gas storage providers in California. For example, in previous transfers of control of Central Valley (A.11-01-021), Lodi (A.07-07-001) and Wild Goose Storage Inc. (A.06-05-033), the Commission approved the transfer on an expedited basis without hearings. Indeed, given that the authorization being requested in this Application is factually less complicated than in Central Valley's prior application (or the applications of either Lodi or Wild Goose), the Joint Applicants submit that the information presented in this Application is more than sufficient to permit the Commission to determine that the proposed transfer of ownership of Central Valley is in the public interest.

18/ Decision Approving Ownership Transfer of Lodi Gas Storage L.L.C., D.14-12-013, A.14-09-00 at 11; Decision Approving Change in Ownership and Control of Central Valley Gas Storage, LLC D.11-05-030 at 8; Opinion Approving Transfer of 100% Interest in Lodi Gas Storage, LLC to Buckeye Gas Storage LLC, D.08-01-018 at 26-27; *In re Joint Application of Wild Goose Storage, Inc., et al.*, D.06-11-019 at 32; Opinion Approving Transfer of 50% Interest in Lodi Holdings, LLC, D.03-02-071 at 25.

VII. RULE 2.1(c) REQUIREMENTS

Pursuant to Rule 2.1(c), Central Valley recommends the following:

A. Categorization

Consistent with the Commission's categorization in other similar proceedings, Central Valley proposes that this proceeding be categorized as ratesetting. Although this Application will not impact the rates of Central Valley's customers, the definitions of "adjudicatory" or "quasi-legislative" as set forth in Rules 1.3(a) and 1.3(d) clearly do not apply to this Application. Rule 7.1(e)(2) specifies that, when a proceeding does not clearly fit into any of the categories, it should be conducted under the rules for ratesetting proceedings. In addition, Rule 1.3(e) defines ratesetting proceedings to include "[o]ther proceedings" that do not fit clearly into any other category.

B. Need for Hearings

The Joint Applicants submit that hearings are unnecessary in this proceeding and that the information submitted in this Application is sufficient to allow the Commission to determine that the transfer of control will have no adverse impact on the public interest. Joint Applicants do not anticipate that any material issues of contested fact will arise regarding this transaction, further supporting the conclusion that hearings are not necessary.

C. Issues to be Considered

The only issue to be considered is whether the described transaction meets the public interest standard of Public Utilities Code section 854(a).

D. Proposed Schedule

Joint Applicants propose the following schedule:

Application filed	November 9, 2015
Public Notice	November 13, 2015

Period for submission of protest expires	December 13, 2015
Reply to comments/protests, if any	December 24, 2015
Proposed Decision Issued	January 25, 2016
Comments on PD (if needed)	February 14, 2016
Reply Comments on PD (if needed)	February 21, 2016
Final Commission Decision	February 25, 2016

E. Compliance with Procedural Requirements

This section cross-references compliance with the Rules applicable to this Application:

Rule 2.1	Section II.A-C; Section VII
Rule 2.2.	Section II.D; Exhibits 1-2
Rule 2.3	Section II.D; Exhibits 3-8
Rule 2.4	Section V
Rule 3.6	Section III

VIII. CONCLUSION

WHEREFORE, Joint Applicants respectfully request that the Commission issue an Order to become effective upon the date of issuance as follows:

1. Grant this Application for authorization, pursuant to Section 854(a) of the Public Utilities Code, for the transfer of ownership of Central Valley to Southern Company;

2. Grant Commission confirmation that CEQA does not apply to this transaction; and respect to the authorization sought herein as the Commission may deem appropriate.

3. Grant such additional authorization or further relief to Joint Applicants with respect to the authorization sought herein as the Commission may deem appropriate.

Respectfully submitted,

By: ________/s/__________
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paul.lacourciere@troutmansanders.com

Attorney for Southern Company

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christopher.schindler@hoganlovells.com

Counsel for AGL Resources and Central Valley Gas Storage

Dated: November 9, 2015

EXHIBITS TO APPLICATION

Exhibit 1 Certificate of Formation of Central Valley Gas Storage, LLC

Exhibit 2 Certificate of Registration issued by the Secretary of State for Central Valley Gas Storage, LLC

Exhibit 3 AGLR 2014 Annual Report to Shareholders

Exhibit 4 AGLR 2014 Proxy Statement

Exhibit 5 AGLR 2014 Annual Report on Form 10-K

Exhibit 6 Southern Company 2014 Annual Report to Shareholders

Exhibit 7 Southern Company 2014 Proxy Statement

Exhibit 8 Southern Company 2014 Annual Report on Form 10-K

Exhibit 9 Agreement and Plan of Merger, dated August 23, 2015

Exhibit 10 Diagrams showing the corporate organization structure prior to and after the proposed transaction.

Exhibit 11 Listing of Southern Company solar assets in California

VERIFICATION OF APPLICATION

CENTRAL VALLEY GAS STORAGE, LLC

I, Stephen Cittadine, hereby declare that I have read the foregoing Joint Application; and that the information set forth therein concerning such entities is true and correct to the best of my knowledge.

I declare under penalty of perjury that the foregoing issue is true and correct.

Executed this 5th day of November, 2015

Stephen Cittadine
President
Central Valley Gas Storage, LLC

VERIFICATION OF APPLICATION

AGL RESOURCES INC.

I, Dat Tran, hereby declare that I have read the foregoing Joint Application; and that the information set forth therein concerning such entities is true and correct to the best of my knowledge.

I declare under penalty of perjury that the foregoing issue is true and correct.

Executed this 5th day of November, 2015

Dat T. Tran
Vice President and Associate General Counsel
AGL Resources Inc.

VERIFICATION OF APPLICATION

SOUTHERN COMPANY.

I, James Y. Kerr II, hereby declare that I have read the foregoing Joint Application; and that the information set forth therein concerning such entities is true and correct to the best of my knowledge.

I declare under penalty of perjury that the foregoing issue is true and correct.

Executed this 6th day of November, 2015

James Y. Kerr II

James Y. Kerr II
Executive Vice President, General Counsel and Chief Compliance Officer
The Southern Company

Exhibit 1

Delaware

The First State

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF FORMATION OF "CENTRAL VALLEY GAS STORAGE, L.L.C.", FILED IN THIS OFFICE ON THE SIXTH DAY OF FEBRUARY, A.D. 2008, AT 7:39 O'CLOCK P.M.

SECRETARY'S OFFICE 1793 DELAWARE 1855

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

4501127 8100

AUTHENTICATION: 6367703

080128251

DATE: 02-07-08

Delaware

The First State

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY "CENTRAL VALLEY GAS STORAGE, L.L.C." IS DULY FORMED UNDER THE LAWS OF THE STATE OF DELAWARE AND IS IN GOOD STANDING AND HAS A LEGAL EXISTENCE SO FAR AS THE RECORDS OF THIS OFFICE SHOW, AS OF THE SEVENTH DAY OF FEBRUARY, A.D. 2008.

AND I DO HEREBY FURTHER CERTIFY THAT THE ANNUAL TAXES HAVE NOT BEEN ASSESSED TO DATE.

SECRETARY'S OFFICE 1793 DELAWARE 1855

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

4501127 8300

AUTHENTICATION: 6367704

080128251

DATE: 02-07-08

You may verify this certificate online
at corp.delaware.gov/authver.shtml

Delaware

The First State

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY "CENTRAL VALLEY GAS STORAGE, L.L.C." IS DULY FORMED UNDER THE LAWS OF THE STATE OF DELAWARE AND IS IN GOOD STANDING AND HAS A LEGAL EXISTENCE SO FAR AS THE RECORDS OF THIS OFFICE SHOW, AS OF THE SEVENTH DAY OF FEBRUARY, A.D. 2008.

AND I DO HEREBY FURTHER CERTIFY THAT THE ANNUAL TAXES HAVE NOT BEEN ASSESSED TO DATE.

SECRETARY'S OFFICE 1793 DELAWARE 1855

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

4501127 8300

AUTHENTICATION: 6367705

080128251

DATE: 02-07-08

You may verify this certificate online at corp.delaware.gov/authver.shtml

Delaware

The First State

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED ARE TRUE AND CORRECT COPIES OF ALL DOCUMENTS ON FILE OF "CENTRAL VALLEY GAS STORAGE, L.L.C." AS RECEIVED AND FILED IN THIS OFFICE.

THE FOLLOWING DOCUMENTS HAVE BEEN CERTIFIED:

CERTIFICATE OF FORMATION, FILED THE SIXTH DAY OF FEBRUARY, A.D. 2008, AT 7:39 O'CLOCK P.M.

AND I DO HEREBY FURTHER CERTIFY THAT THE AFORESAID CERTIFICATES ARE THE ONLY CERTIFICATES ON RECORD OF THE AFORESAID LIMITED LIABILITY COMPANY, "CENTRAL VALLEY GAS STORAGE, L.L.C.".

SECRETARY'S OFFICE 1793 DELAWARE 1855

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

4501127 8100H

AUTHENTICATION: 6367706

080128251

DATE: 02-07-08

You may verify this certificate online at corp.delaware.gov/authver.shtml

State of Delaware
Secretary of State
Division of Corporations
Delivered 08:57 PM 02/06/2008
FILED 07:39 PM 02/06/2008
SRV 080128251 - 4501127 FILE

CERTIFICATE OF FORMATION

OF

Central Valley Gas Storage, L.L.C.

1. The name of the limited liability company is Central Valley Gas Storage, L.L.C.

2. The address of its registered office in the State of Delaware is: The Corporation Trust Center, 1209 Orange Street, in the City of Wilmington, Delaware 19801. The name of its registered agent at such address is The Corporation Trust Company.

IN WITNESS WHEREOF, the undersigned has executed this Certificate of Formation of Central Valley Gas Storage, L.L.C. this 6th day of February, 2008.

Nicor Energy Ventures Company – Member
Daniel R. Dodge - President

Exhibit 2

STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

DESIGNATION OF AGENT

In compliance with Section 3200 of the Public Resources Code, notice is hereby given and we hereby certify

that Central Valley Gas Storage, L.L.C.,
(Name of Operator)

an LLC organized and existing under and by virtue of the laws of the State of Delaware.

has appointed, authorized, and empowered CT Corporation System,
(Name of Individual)

whose address (where legal papers may be served) is 818 W. Seventh Street,
(Street Address and P.O. Box)

Los Angeles (Attention: Jere Keprios), California 90017, (213) 627-8252, as its
(City) (Zip Code) (Telephone Number)

agent for the State of California* N/A upon whom all orders, notices, and processes of the Supervisor or any court of law may be served. This notice revokes all former appointments made for this purpose.

IN WITNESS WHEREOF, the corporation has caused this certificate to be signed by its President and attested by its Secretary on

March 2nd, 2009.
(Date) (Year)

By [signature]
(Signature of the President)
Stephen Cittadine
(Printed or Typed Name)
Central Valley Gas Storage, L.L.C.
(Printed or Typed Name of Operator)

Attest: [signature]
(Signature of the Secretary)
Daniel G. McNamara
(Printed or Typed Name)

Acceptance of Appointment as Agent:
Accepted [signature] 3/4/2009
(Signature) (Date)

CORPORATE SEAL

Sec. 3200. Every owner or operator of any well shall designate an agent, giving his or her address, who resides in this state, to receive and accept service of all orders, notices, and processes of the supervisor or any court of law. Every person so appointing an agent shall, within five days after the termination of the agency, notify the supervisor, in writing, of the termination, and unless operations are discontinued, shall appoint a new agent.

NOTE: An operator may appoint himself or herself as agent.

* Should the owner or operator filing this form choose to appoint more than one agent, the phrase "the State of California" should be deleted and the exact area for which the agent is to be appointed should be inserted in the blank. If more space is needed, please use the reverse side. A separate form must be filed for each agent appointed.
OG134A (7/98)

State of California
Secretary of State

I, DEBRA BOWEN, Secretary of State of the State of California, hereby certify:

That the attached transcript of 1 page(s) has been compared with the record on file in this office, of which it purports to be a copy, and that it is full, true and correct.

IN WITNESS WHEREOF, I execute this certificate and affix the Great Seal of the State of California this day of

FEB 13 2008

Debra Bowen

DEBRA BOWEN
Secretary of State

LLC-5 File # 200804410177

State of California
Secretary of State

ENDORSED - FILED
In the office of the Secretary of State
of the State of California

FEB 13 2008

LIMITED LIABILITY COMPANY
APPLICATION FOR REGISTRATION

A $70.00 filing fee AND a certificate of good standing from an authorized public official of the jurisdiction of formation must accompany this form.

IMPORTANT – Read instructions before completing this form.

This Space For Filing Use Only

ENTITY NAME (End the name in Item 1 with the words "Limited Liability Company," or the abbreviations "LLC" or "L.L.C." The words "Limited" and "Company" may be abbreviated to "Ltd." and "Co.," respectively.)

1. NAME UNDER WHICH THE FOREIGN LIMITED LIABILITY COMPANY PROPOSES TO REGISTER AND TRANSACT BUSINESS IN CALIFORNIA

Central Valley Gas Storage, L.L.C.

2. NAME OF THE FOREIGN LIMITED LIABILITY COMPANY, IF DIFFERENT FROM THAT ENTERED IN ITEM 1 ABOVE

DATE AND PLACE OF ORGANIZATION

3. THIS FOREIGN LIMITED LIABILITY COMPANY WAS FORMED ON 02 (MONTH) - 06 (DAY) - 2008 (YEAR) IN Delaware (STATE OR COUNTRY)

AND IS AUTHORIZED TO EXERCISE ITS POWERS AND PRIVILEGES IN THAT STATE OR COUNTRY.

AGENT FOR SERVICE OF PROCESS (If the agent is an individual, the agent must reside in California and both Items 4 and 5 must be completed. If the agent is a corporation, the agent must have on file with the California Secretary of State a certificate pursuant to Corporations Code section 1505 and Item 4 must be completed (leave Item 5 blank).

4. NAME OF AGENT FOR SERVICE OF PROCESS

C T Corporation System

5. IF AN INDIVIDUAL, ADDRESS OF INITIAL AGENT FOR SERVICE OF PROCESS IN CALIFORNIA CITY STATE ZIP CODE

CA

APPOINTMENT (The following statement is required by statute and should not be altered.)

6. IN THE EVENT THE ABOVE AGENT FOR SERVICE OF PROCESS RESIGNS AND IS NOT REPLACED, OR IF THE AGENT CANNOT BE FOUND OR SERVED WITH THE EXERCISE OF REASONABLE DILIGENCE, THE SECRETARY OF STATE OF THE STATE OF CALIFORNIA IS HEREBY APPOINTED AS THE AGENT FOR SERVICE OF PROCESS OF THIS FOREIGN LIMITED LIABILITY COMPANY.

OFFICE ADDRESSES (Do not abbreviate the name of the city.)

7. ADDRESS OF THE PRINCIPAL EXECUTIVE OFFICE	CITY AND STATE	ZIP CODE
3333 Warrenville Road - Suite 630	Lisle, IL	60532

8. ADDRESS OF THE PRINCIPAL OFFICE IN CALIFORNIA, IF ANY	CITY	STATE	ZIP CODE
		CA	

EXECUTION

9. I DECLARE I AM THE PERSON WHO EXECUTED THIS INSTRUMENT, WHICH EXECUTION IS MY ACT AND DEED.

2-11-08
DATE

SIGNATURE OF AUTHORIZED PERSON

Daniel R. Dodge, President, Nicor Energy Ventures Company
TYPE OR PRINT NAME AND TITLE OF AUTHORIZED PERSON

 APPROVED BY SECRETARY OF STATE

OFFICE OF THE SECRETARY OF STATE

State of California
Secretary of State

I, DEBRA BOWEN, Secretary of State of the State of California, hereby certify:

That the attached transcript of 1 page(s) has been compared with the record on file in this office, of which it purports to be a copy, and that it is full, true and correct.

IN WITNESS WHEREOF, I execute this certificate and affix the Great Seal of the State of California this day of

FEB 13 2008

Debra Bowen

DEBRA BOWEN
Secretary of State

LLC-5 File # 200804410177

State of California
Secretary of State

ENDORSED - FILED
In the office of the Secretary of State
of the State of California

FEB 13 2008

LIMITED LIABILITY COMPANY APPLICATION FOR REGISTRATION

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		CA	

APPOINTMENT (The following statement is required by statute and should not be altered.)

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OFFICE ADDRESSES (Do not abbreviate the name of the city.)

7. ADDRESS OF THE PRINCIPAL EXECUTIVE OFFICE	CITY AND STATE	ZIP CODE
3333 Warrenville Road - Suite 630	Lisle, IL	60532

8. ADDRESS OF THE PRINCIPAL OFFICE IN CALIFORNIA, IF ANY	CITY	STATE	ZIP CODE
		CA	

EXECUTION

9. I DECLARE I AM THE PERSON WHO EXECUTED THIS INSTRUMENT, WHICH EXECUTION IS MY ACT AND DEED.

2-11-08
DATE

SIGNATURE OF AUTHORIZED PERSON

Daniel R. Dodge, President, Nicor Energy Ventures Company
TYPE OR PRINT NAME AND TITLE OF AUTHORIZED PERSON

OFFICE OF THE SECRETARY OF STATE

State of California
Secretary of State

CERTIFICATE OF REGISTRATION

I, DEBRA BOWEN, Secretary of State of the State of California, hereby certify:

That on the **13th day of February**, **2008, CENTRAL VALLEY GAS STORAGE, L.L.C.**, complied with the requirements of California law in effect on that date for the purpose of registering to transact intrastate business in the State of California; and further purports to be a limited liability company organized and existing under the laws of **Delaware** as **CENTRAL VALLEY GAS STORAGE, L.L.C.** and that as of said date said limited liability company became and now is duly registered and authorized to transact intrastate business in the State of California, subject, however, to any licensing requirements otherwise imposed by the laws of this State.

IN WITNESS WHEREOF, I execute this certificate and affix the Great Seal of the State of California this day of February 13, 2008.

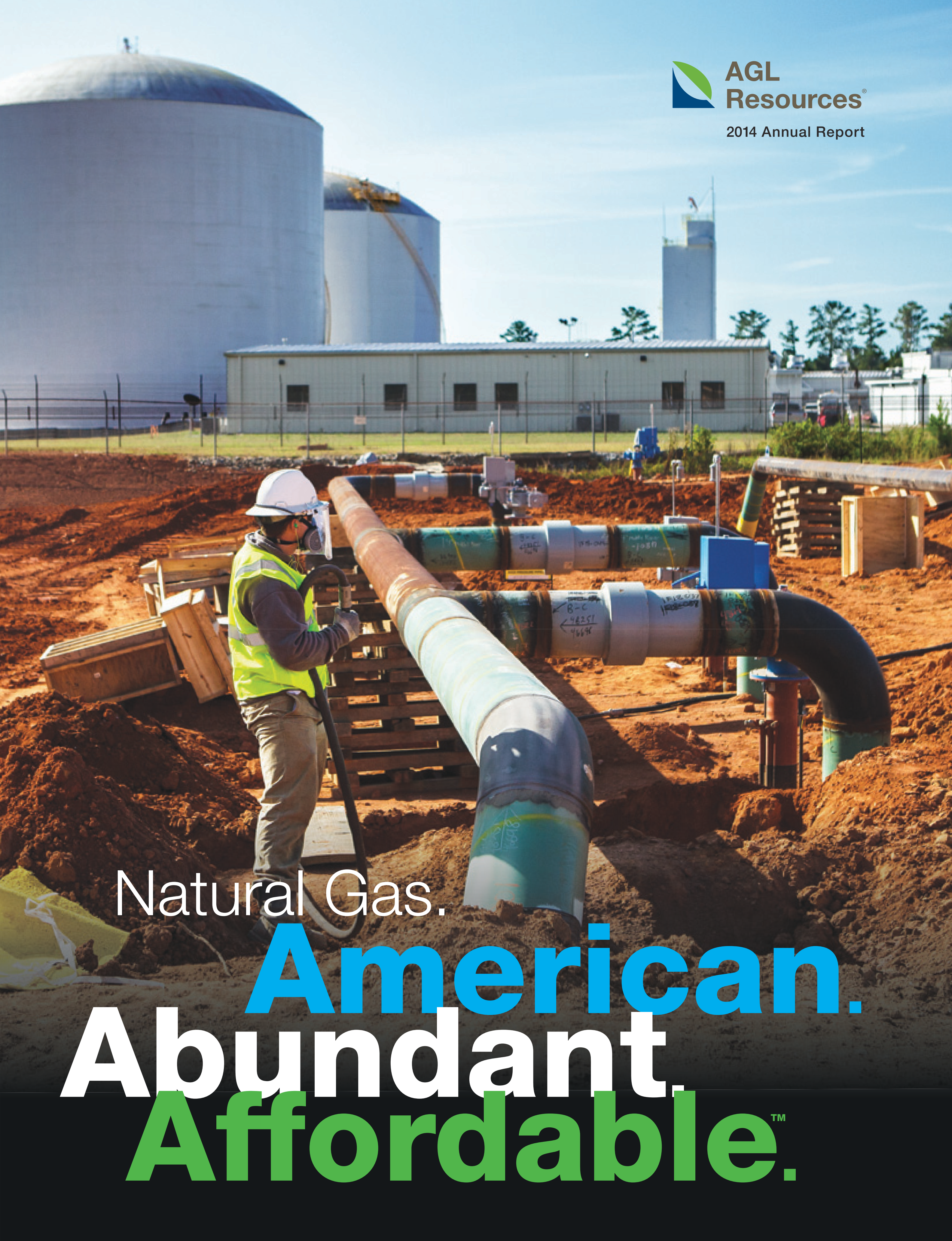
DEBRA BOWEN
Secretary of State

lmp

NP-25 (REV 1/2007)

OSP 06 99731

Exhibit 3



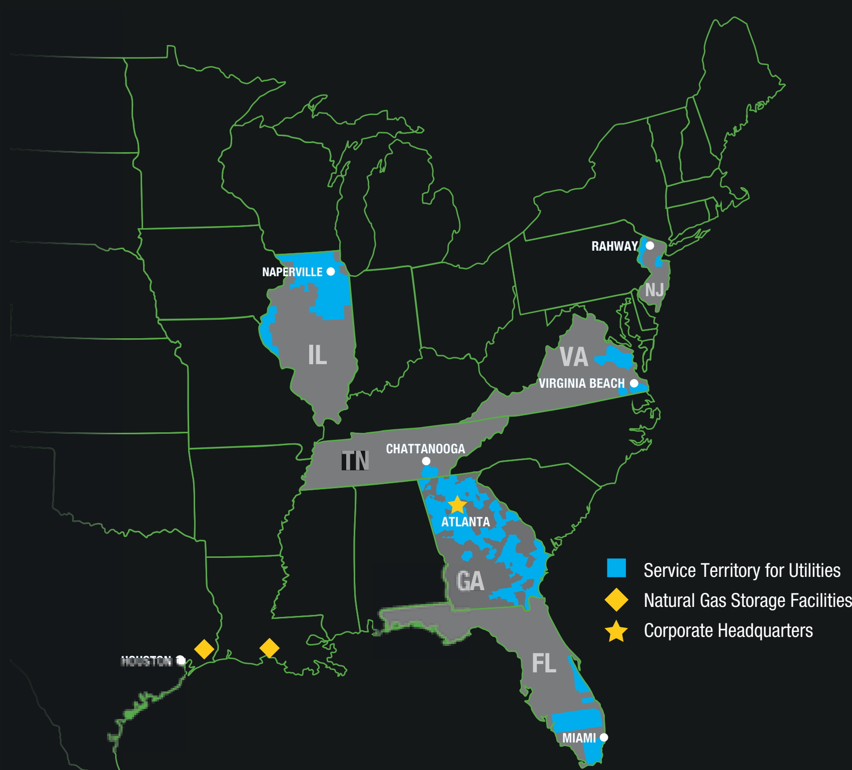
AGL Resources®

2014 Annual Report

Natural Gas. American. Abundant. Affordable.™

John W. Somerhalder II
Chairman, President and
Chief Executive Officer

AGL Resources serves approximately 4.5 million end-use customers in seven states through its utility subsidiaries within the distribution operations segment: Nicor Gas in Illinois, Atlanta Gas Light in Georgia, Virginia Natural Gas in Virginia, Elizabethtown Gas in New Jersey, Florida City Gas in Florida, Chattanooga Gas in Tennessee and Elkton Gas in Maryland. Our retail operations segment serves 0.6 million energy customers and 1.2 million service contracts and markets natural gas and related home services to end-use customers across 15 states. Our Houston-based wholesale services segment engages in natural gas storage and gas pipeline arbitrage and provides natural gas asset management and/or related logistics services for most of our utilities, as well as for non-affiliated companies. Our midstream operations segment provides natural gas storage and related activities and engages in the development and operations of high-deliverability natural gas storage facilities.



To Our Shareholders

2014 was the strongest year in AGL Resources' history, with consolidated earnings before interest and taxes (EBIT) of more than $1 billion, driven largely by record results in the wholesale services segment and bolstered by solid year-over-year growth in our distribution operations segment. Excluding the sale of Tropical Shipping that occurred in 2014, earnings per share (EPS) rose 92%, and our total shareholder return was 20%.

We executed on several strategic initiatives in 2014, including the sale of Tropical Shipping and the announcement of partnership investments totaling approximately $670 million in three major interstate pipelines. Importantly, we continue investing across all of our jurisdictions to ensure the safety and reliability of our systems. In addition to the successful pipeline replacement programs already in place in Georgia, New Jersey and Virginia (as depicted on the front and inside cover), we now are embarking on a nine-year infrastructure replacement program in Illinois that will enable us to spend approximately $200 million per year for system maintenance and upgrades. These programs all support state and federal efforts to modernize our nation's natural gas pipeline network.

For the majority of my tenure at AGL Resources, we have projected annual EPS growth in the range of 4% to 6%. With the initiatives noted above, we now expect an increase in our compound annual growth rate (CAGR) of earnings to a range of 5% to 8% over the next three years, compared to normalized 2014 results. Further, we anticipate this growth to accelerate to 6% to 9% over a five-year period. This higher projected growth rate is due largely to our ability to earn near our authorized rate of return in each jurisdiction that we serve through prudent investment and rigorous cost control. In addition, we have pursued and secured investments, such as those in interstate pipelines noted above, that generate returns in line with, or above, those of our regulated utilities.

Consistent with our strong performance in 2014, our Board of Directors in February approved our 13th consecutive annual dividend increase. For the second year in a row, we increased the dividend by more than 4%, and our indicated annual dividend now stands at $2.04 per share.

DISTRIBUTION OPERATIONS

In 2014 EBIT improved by $35 million, or 6%, compared to 2013 for our distribution operations segment, which includes our seven regulated utilities in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland. The primary drivers of the increase were higher customer usage and growth, colder-than-normal weather in 2014 and higher revenues from our infrastructure investment programs. In addition, we effectively managed our operating expenses, which rose less than 2% — commensurate with the rate of inflation.

Natural gas continues to have a strong cost advantage over many other fuel sources. This fact, combined with successful marketing programs and system expansion into unserved or under-served areas, led to strong new customer growth in 2014. We added approximately 34,000 net meters in 2014 compared to approximately 27,000 in 2013, an increase of over 25%.

FINANCIAL HIGHLIGHTS

In millions, except per share amounts

	2014	2013
Operating revenues	**$ 5,385**	$ 4,209
Income from continuing operations	**$ 562**	$ 290
(Loss) income from discontinued operations, net of tax	**$ (80)**	$ 5
Net income attributable to AGL Resources Inc.	**$ 482**	$ 295
Diluted earnings per common share from continuing operations attributable to AGL Resources Inc.	**$ 4.71**	$ 2.45
Diluted earnings per common share attributable to AGL Resources Inc.	**$ 4.04**	$ 2.49
Market capitalization	**$ 6,522**	$ 5,615
Total assets	**$ 14,909**	$ 14,550
Total shareholder return	**20%**	23%

As mentioned, we have pipeline replacement and improvement programs underway in nearly every jurisdiction. We pioneered these efforts among regulated utilities starting in the 1990s. In total, we have spent approximately $1.5 billion to modernize more than 2,500 miles of pipeline across our system, and we now are embarking on a $1.5 billion program in Illinois. These programs benefit our customers as they keep our systems best-in-class in terms of safety and reliability. They also are cost-effective by reducing the need for expensive and time-consuming general rate cases. Finally, our shareholders also garner benefits as the time to recover investment in these programs is reduced due to the rider-based regulatory constructs under which we operate. In part because of significant investment in these programs, we do not anticipate any general rate case filings in 2015.

In addition to safety and reliability improvements, we also are committed to environmental matters, including the reduction of greenhouse gases (GHG). We have been a leader in activities to reduce GHGs since 1993, when we joined the Environmental Protection Agency's (EPA's) Natural Gas STAR Program as an original participant. The Natural Gas STAR Program provides a framework to encourage partner companies to implement methane emissions-reducing technologies and practices and document their voluntary emission reduction activities. In addition, we are one of seven in the natural gas value chain, and one of only two utilities, to form Our Nation's Energy Future (also known as "ONE Future"), which has the goal of reducing methane-leak loss rates across the value chain to less than 1%, a level that science indicates is not only cost-effective and attainable, but the point at which natural gas will remain the fuel of choice from a climate perspective. The EPA cited the ONE Future initiative as one it is committed to continue to work with to develop and verify robust commitments to reduce methane emissions.

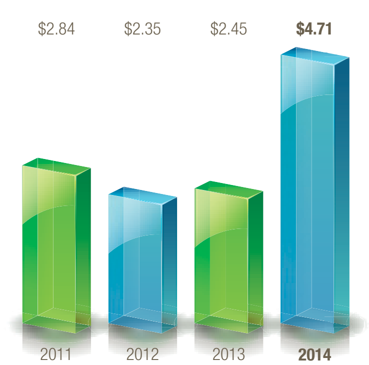
RETAIL OPERATIONS

Our retail operations segment includes the sale of natural gas to customers who have the option to choose their natural gas provider, as well as the provision of maintenance and warranty products for certain home utility services and appliances. We offer these products in 15 states. The retail operations segment reported EBIT of $132 million in 2014, in line with results from 2013. On an operational basis, the retail segment had very strong performance during a period of colder-than-normal weather. However, we also recorded hedge losses and inventory adjustments of $16 million in 2014; those losses are related to mark-to-market accounting and are expected to be substantially recognized as income in 2015 as the gas is delivered to customers. We continue to maintain our market-leading position in Georgia — our largest market – and we have been successful in expanding our service offerings across our entire retail footprint.

WHOLESALE SERVICES

Our wholesale services segment manages and optimizes natural gas storage inventory and pipeline transportation capacity for six of our utilities under asset management agreements approved by the regulatory commissions in those jurisdictions. We also provide asset management, optimization, producer and peaking services for other electric and natural gas utilities, power generation and large industrial customers around the country. Our 2014 EBIT for the segment of $422 million was the strongest in the company's history and drove our record consolidated earnings for the year. Earnings in this business in 2013 were muted by mark-to-market accounting losses, but our 2014 results reflect the recognition of prior-period economic earnings generation, as well as strong commercial activity generated during the year. Our wholesale business provides investors a low-risk option on the natural gas commodity markets and, as demonstrated in 2014, can generate significant value during periods of volatility in those markets.

ADJUSTED DILUTED EARNINGS PER SHARE[1]

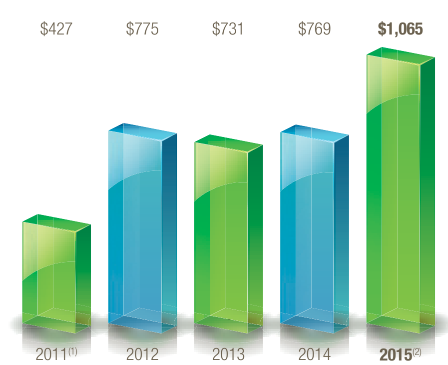


(1) For a reconciliation of adjusted EPS (which excludes costs related to the Nicor merger and additional accrual for the Nicor Gas PBR issue) to GAAP EPS, see our non-GAAP reconciliation section included within this report.

INDICATED ANNUAL DIVIDEND PER SHARE

(1) Indicated 2011 and 2012 dividend rate. As a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011, received a pro rata dividend of $.0.0989 for the stub period accruing from November 19, 2011 for a total dividend of $1.90. This same $0.0989 would have been added to the $1.74 dividends paid in 2012 if it were not for the Nicor merger.

CAPITAL EXPENDITURES
(In Millions)



(1) Amount for 2011 only includes Nicor expenditures subsequent to the merger date of December 9, 2011.
(2) Amount for 2015 is an estimate and is subject to change.

MIDSTREAM OPERATIONS

Our midstream operations segment consists primarily of high-deliverability natural gas storage facilities. EBIT in the segment declined by $7 million in 2014 compared to 2013. The change year-over-year was due largely to a one-time true up of natural gas storage inventory at one of our facilities as well as expected recontracting at lower rates.

Conditions in the storage market remain challenged, and market fundamentals are substantially different than when we first began investing in storage facilities nearly a decade ago. As a result, contracts we signed several years ago that are expiring or near expiration are being recontracted at significantly lower rates. We have seen a modest improvement in storage rates from 2013 to 2014; however, we expect it will take several more years for the market to recover to more robust and profitable levels.

One of our most exciting business opportunities came to fruition in 2014. Over the course of the year, we announced investments totaling approximately $670 million in three interstate pipelines. The pipelines, detailed below, are intended to bring low-cost shale gas to our customers in Georgia, New Jersey and Virginia. In addition to taking an ownership stake in these pipelines, in each instance we also have signed long-term capacity arrangements. These investments provide significant benefits to our customers in terms of access to low-cost natural gas supplies, and to our shareholders from the standpoint of generating solid investment returns. We expect to start realizing earnings from these pipeline investments in 2017.

Dollars in millions	Miles of Pipe	Expected capital expenditures [1]	Ownership Interest [1]	Scheduled year of completion
Dalton Pipeline	106	$210	50%	2017
PennEast Pipeline	108	200	20%	2017
Atlantic Coast Pipeline	550	260	5%	2018
Total	764	$670		

[1] Represents our expected capital expenditures and ownership interest, which may change.

PRIORITIES FOR 2015

Our business strategy for 2015 is consistent with prior years and representative of our safety- and customer-focused, steady-growth culture. Our focus is to capitalize on margin-enhancing opportunities across all business units, while ensuring efficient and safe operations. Several of our specific business objectives are detailed below:

- **Distribution operations:** Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand our system and capitalize on potential customer conversions.
- **Retail operations:** Maintain market-leading position in Georgia and focus on margin growth in all markets; expand our overall market reach.
- **Wholesale services:** Maximize storage and transportation portfolio; effectively perform on existing asset management agreements and expand customers; grow gas supply to power generation markets.
- **Midstream operations:** Optimize storage portfolio, including expiring contracts; execute, in conjunction with partners, on interstate pipeline investments; pursue land-based LNG transportation opportunities.

In addition to these operational objectives, we target the following shareholder objectives:

- Generate EPS growth of 5% – 8% on a three-year CAGR basis, and 6% – 9% on a five-year basis;
- Grow rate base by 7% – 9% on a five-year CAGR rate basis;
- Fund all capital expenditure requirements with cash from operations and debt issuance, while remaining in our current credit ratings categories (no planned equity issuance at this time);
- Deploy surplus cash from wholesale services into businesses that generate a regulated rate of return; and
- Maintain a dividend payout ratio that is generally consistent with our peer group.

We are proud of our accomplishments in 2014 and confident that we have developed a strong platform for the long-term growth and success of our company. We provided 2015 earnings guidance in the range of $2.65 to $2.75 per diluted share, excluding our wholesale services segment, and $2.70 to $2.90 on a consolidated basis. Consolidated earnings are likely to vary due to mark-to-market movements associated with our retail operations and wholesale services businesses, as previously noted.

American, abundant and affordable natural gas remains at the forefront of our country's energy future. As one of the largest regulated natural gas providers in the United States, we are well positioned to capitalize on the many opportunities that lie ahead for our customers, our company and our shareholders.

Sincerely,

John W. Somerhalder II
Chairman, President and Chief Executive Officer

February 27, 2015

Board of Directors

Sandra N. Bane [1,2]
Retired Audit Partner, KPMG, LLP
Director since 2008

Thomas D. Bell, Jr. [2,4]
Chairman of Mesa Capital Partners, LLC
Director since 2004

Norman R. Bobins [1,2]
President and CEO of Norman Bobins Consulting, LLC
Director since 2011

Charles R. Crisp [2,4]
Retired CEO and Director of Coral Energy, a subsidiary of Shell Oil Company
Director since 2003

Brenda J. Gaines [1,5]
Retired President and CEO of Diners Club North America, a division of Citigroup
Director since 2011

Arthur E. Johnson [3*,4,5]
Lead Director of the Board of Directors of AGL Resources and Retired Senior Vice President, Lockheed Martin Corporation
Director since 2002

Wyck A. Knox, Jr. [1,5]
Retired Partner in Kilpatrick, Townsend & Stockton, LLP
Director since 1998

Dennis M. Love [1,3,5*]
President and CEO, Printpack, Inc.
Director since 1999

Dean R. O'Hare [1,5]
Retired Chairman and Chief Executive Officer, The Chubb Corporation
Director since 2005

Armando J. Olivera [2,4]
Retired President and CEO of Florida Power & Light Company
Director since 2011

John E. Rau [3,4,5]
President and CEO of Miami Corporation
Director since 2011

James A. Rubright [2,3,4*]
Former Chairman and CEO, RockTenn Company
Director since 2001

John W. Somerhalder II [3,4]
Chairman, President and Chief Executive Officer
Director since 2006

Bettina M. Whyte [2*,3,4]
Managing Director and Senior Advisor, Alvarez & Marsal Holdings, LLC
Director since 2004

Henry C. Wolf [1*,2,3]
Retired Vice Chairman and Chief Financial Officer of Norfolk Southern Corporation
Director since 2004

* Committee Chair
1 Audit
2 Compensation
3 Executive
4 Finance and Risk Management
5 Nominating, Governance and Corporate Responsibility

Executive Officers

John W. Somerhalder II
Chairman, President and Chief Executive Officer

Andrew W. Evans
Executive Vice President and Chief Financial Officer

Henry P. Linginfelter
Executive Vice President, Distribution Operations

Paul R. Shlanta
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer

Peter I. Tumminello
Executive Vice President, Wholesale Services, and President, Sequent Energy Management

Melanie M. Platt
Executive Vice President, Chief People Officer and President, AGL Resources Foundation

Shareholder Information

Corporate Headquarters
AGL Resources Inc., Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; website: aglresources.com.

Stock Exchange Listing
Our common stock is traded on the New York Stock Exchange under the symbol "GAS" and quoted in The Wall Street Journal as "AGL Res."

Transfer Agent and Registrar
Wells Fargo serves as our transfer agent and registrar and can help with a variety of stock-related matters, including name and address changes; transfer of stock ownership; lost certificates; and Form 1099s.

Inquiries may be directed to: Wells Fargo Shareowner Services, P.O. Box 64874, St. Paul, MN 55164-0874; toll-free 800-468-9716; website: wellsfargo.com/shareownerservices.

Available Informatiom
A copy of this Annual Report, as well as our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, other reports that we file with or furnish to the Securities and Exchange Commission (SEC) and our recent news releases are available free of charge at our website, aglresources.com, as soon as reasonably practicable. The information contained on our website should not be considered part of this document and is not incorporated by reference.

Our Annual Report on Form 10-K includes the certifications of our chief executive officer and chief financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. Additionally, we have filed the most recent annual CEO certification as required by Section 303A. 12(a) of the New York Stock Exchange Listed Company Manual pursuant to which our CEO certified to the NYSE that he was not aware of any violation by AGL Resources of the NYSE's corporate governance listing standards.

Our corporate governance guidelines; our code of ethics for the CEO and senior financial officers; our code of conduct and ethics; and the charters of our Board committees also are available on our website.

The above information and any exhibit to our 2014 Form 10-K also will be furnished free of charge upon written request to our Investor Relations department at Sarah Stashak, Director, Investor Relations, AGL Resources, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; sstashak@aglresources.com.

Institutional Investor Inquiries
Institutional investors and securities analysts should direct inquiries to Sarah Stashak, Director, Investor Relations, AGL Resources, Ten Peachtree Place, N.E., Atlanta, GA 30309; 404-584-4000; sstashak@aglresources.com.

GAAP Reconciliation

	Year Ended December 31, 2014	2013	2012	2011
Diluted earnings per share from continuing operations	**$ 4.71**	$2.45	$2.20	$2.04
Additional accrual for Nicor Gas PBR issue	**—**	—	0.04	—
Transaction costs for Nicor merger	**—**	—	0.11	0.80
Diluted earnings per share - as adjusted	**$ 4.71**	$2.45	$2.35	$2.84

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014

Commission File Number 1-14174

AGL RESOURCES INC.

Ten Peachtree Place NE,
Atlanta, Georgia 30309

404-584-4000

Georgia	**58-2210952**
(State of incorporation)	(I.R.S. Employer Identification No.)

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

Title of each class	Name of each exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**

AGL Resources Inc. is a well-known seasoned issuer.

AGL Resources Inc. is required to file reports pursuant to Section 13 of the Securities Exchange Act.

AGL Resources Inc.: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

AGL Resources Inc. has submitted electronically and posted on its corporate website every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months.

AGL Resources Inc. believes that during the 2014 fiscal year, its executive officers, directors and 10% beneficial owners subject to Section 16(a) of the Securities Exchange Act complied with all applicable filing requirements, except as set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in AGL Resources Inc.’s Proxy Statement for the 2015 Annual Meeting of Shareholders.

AGL Resources Inc. is a large accelerated filer and is not a shell company.

The aggregate market value of AGL Resources Inc.’s common stock held by non-affiliates of the registrant (based on the closing sale price on June 30, 2014, as reported by the New York Stock Exchange), was $6,574,107,387.

The number of shares of AGL Resources Inc.’s common stock outstanding as of February 4, 2015 was 119,656,937

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2015 Annual Meeting of Shareholders (Proxy Statement) to be held on April 28, 2015, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF KEY TERMS

AFUDC	Allowance for funds used during construction, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
AGL Resources	AGL Resources Inc., together with its consolidated subsidiaries
Atlanta Gas Light	Atlanta Gas Light Company
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Chicago Hub	A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies
Compass Energy	Compass Energy Services, Inc., which was sold in 2013
Dalton Pipeline	A 50% undivided ownership interest in a pipeline facility in Georgia
EBIT	Earnings before interest and taxes, the primary measure of our reportable segments' profit or loss, which includes operating income and other income and excludes financing costs, including interest on debt and income tax expense
EPA	U.S. Environmental Protection Agency
ERC	Environmental remediation costs associated with our distribution operations segment that are generally recoverable through rate mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Georgia Natural Gas	The trade name under which SouthStar does business in Georgia
Golden Triangle	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Horizon Pipeline	Horizon Pipeline Company, LLC
HVAC	Heating, ventilation and air conditioning
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LDC	Local Distribution Company
LIBOR	London Inter-Bank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
MGP	Manufactured gas plant
Moody's	Moody's Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold and revenue tax expense
OTC	Over-the-counter
Pad gas	Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility, also known as base gas
PBR	Performance-based rate, a regulatory plan at Nicor Gas that provided economic incentives based on natural gas cost performance. The plan terminated in 2003
PennEast Pipeline	PennEast Pipeline Company, LLC
PGA	Purchased Gas Adjustment
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, doing business as Pivotal Home Solutions
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SouthStar	SouthStar Energy Services LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Triton	Triton Container Investments LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited
U.S.	United States
VaR	Value-at-risk is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability.
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
WACC	Weighted average cost of capital
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

PART I

ITEM 1. BUSINESS

Unless the context requires otherwise, references to “we,” “us,” “our” and the “company” are intended to mean AGL Resources Inc. The operations and businesses described in this filing are owned and operated, and management services are provided, by distinct direct and indirect subsidiaries of AGL Resources. AGL Resources was organized and incorporated in 1995 under the laws of the State of Georgia.

Business Overview

AGL Resources, headquartered in Atlanta, Georgia, is an energy services holding company whose primary business is the distribution of natural gas through our natural gas distribution utilities. We also are involved in several other businesses that are mainly related and complementary to our primary business. Our segments consist of the following four reportable segments, which are consistent with how management views and manages our businesses.

Distribution Operations
- Operation, construction and maintenance of 80,700 miles of natural gas pipeline and 14 storage facilities to provide safe and cost-effective service of natural gas to residential, commercial and industrial customers
- Serves 4.5 million customers across 7 states
- Rates of return are regulated by each individual state in return for exclusive franchises

Retail Operations
- Provision of natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice
- Serves 628,000 energy customers and 1.2 million service contracts across 15 states

Wholesale Services
- Engages in natural gas storage, gas pipeline arbitrage and provides natural gas asset management and/or related logistics services for most of our utilities, as well as for non-affiliated companies
- Serves a variety of customers in the natural gas value chain with operations structured to optimize storage and transportation portfolios under a wide range of market conditions through the use of hedging tools that allow us to capture additional value while limiting risk

Midstream Operations
- Consists primarily of high deliverability natural gas storage facilities and select pipelines, enabling the provision of diverse sources of natural gas supplies to our customers

For more information on our segments, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Results of Operations” and Note 13 to our consolidated financial statements under Item 8 herein.

Distribution Operations

Our distribution operations segment is the largest component of our business and includes seven natural gas local distribution utilities with their primary focus being the safe and reliable delivery of natural gas. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

Utility	State	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas	Illinois	2,195	34,100
Atlanta Gas Light	Georgia	1,560	32,600
Virginia Natural Gas	Virginia	287	5,500
Elizabethtown Gas	New Jersey	281	3,200
Florida City Gas	Florida	105	3,600
Chattanooga Gas	Tennessee	63	1,600
Elkton Gas	Maryland	6	100
Total		4,497	80,700

Competition and Customer Demand

Our utilities do not compete with other distributors of natural gas in their exclusive franchise territories, but face competition from other energy products. Our principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial and industrial markets throughout our service areas for our customers who are considering switching from a natural gas appliance. Accordingly, the potential displacement or replacement of natural gas appliances with electric appliances is a competitive factor.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- change in the availability or price of natural gas and other forms of energy;

- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations; and
- the cost and capability to convert from natural gas to alternative energy products;

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

The natural gas related programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, we partner with numerous third-party entities such as builders, realtors, plumbers, mechanical contractors, architects and engineers to market the benefits of natural gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Recent advances in natural gas drilling in shale producing regions in the U.S. have resulted in historically high supplies of natural gas and historically low prices for natural gas. This dynamic has provided solid cost advantages for natural gas when compared to electricity, fuel oil and propane and opportunities for growth for our businesses.

Sources of Natural Gas Supply and Transportation Services

Procurement plans for natural gas supply and transportation to serve our regulated utility customers are reviewed and approved by our state utility commissions. We purchase natural gas supplies in the open market by contracting with producers, marketers and from our wholly owned subsidiary, Sequent, under asset management agreements in states where this is approved by the state commission. We also contract for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, we may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of our utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities and other supply sources, arranged by either our transportation customers or us. We have consistently been able to obtain sufficient supplies of natural gas to meet customer requirements. We believe natural gas supply and pipeline capacity will be sufficiently available to meet market demands in the foreseeable future.

Utility Regulation and Rate Design

Rate Structures Our utilities operate subject to regulations and oversight of the state regulatory agencies in each of the states served by our utilities with respect to rates charged to our customers, maintenance of accounting records and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. These agencies approve rates designed to provide us the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of the utility plant in service, working capital and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers;
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks;
- reading meters and maintaining underlying customer premise information for Marketers; and
- planning and contracting for capacity on interstate transportation and storage systems.

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia Commission and periodically adjusted. The Marketers add these fixed charges when billing customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light’s revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of our regulated utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. We have various mechanisms, such as weather normalization mechanisms and weather derivative instruments, in place at most of our utilities that limit our exposure to weather changes within typical ranges in these utilities’ respective service areas.

All of our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need nor utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost of this gas through recovery mechanisms approved by the Georgia Commission specific to Georgia's deregulated market. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to environmental remediation and energy efficiency plans. In traditional rate designs, utilities recover a significant portion of their fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by our customers. Three of our utilities have decoupled regulatory mechanisms in place that encourage conservation. We believe that separating, or decoupling, the recoverable amount of these fixed costs from the customer throughput volumes, or amounts of natural gas used by our customers, allows us to encourage our customers' energy conservation and ensures a more stable recovery of our fixed costs. The following table provides regulatory information for our six largest utilities.

$ in millions	Nicor Gas (9)	Atlanta Gas Light	Virginia Natural Gas	Elizabethtown Gas	Florida City Gas	Chattanooga Gas
Authorized return on rate base (1)	8.09%	8.10%	7.38%	7.64%	7.36%	7.41%
Estimated 2014 return on rate base (2)	8.56%	7.80%	6.45%	8.22%	5.37%	7.94%
Authorized return on equity (1)	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2014 return on equity (2)	12.12%	10.16%	8.77%	11.52%	8.41%	11.19%
Authorized rate base % of equity (1)	51.07%	51.00%	45.36%	47.89%	36.77%	46.06%
Rate base included in 2014 return on equity (2)	$1,561	$2,315	$590	$519	$182	$104
Weather normalization (3)			✓	✓		✓
Decoupled or straight-fixed-variable rates (4)		✓	✓			✓
Regulatory infrastructure program rates (5)	✓	✓	✓	✓		
Bad debt rider (6)	✓		✓			✓
Synergy sharing policy (7)		✓				
Energy efficiency plan (8)	✓		✓	✓	✓	✓
Last decision on change in rates	2009	2010	2011	2009	N/A	2010

(1) The authorized return on rate base, return on equity and percentage of equity were those authorized as of December 31, 2014.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction. Rate base includes investments in regulatory infrastructure programs.
(3) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer-than-normal and decreasing amounts charged when weather is colder-than-normal.
(4) Decoupled and straight-fixed-variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers.
(5) Includes programs that update or expand our distribution systems and liquefied natural gas facilities.
(6) Involves the recovery (refund) of the amount of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through purchased gas adjustment (PGA) mechanisms.
(7) Involves the recovery of 50% of net synergy savings achieved on mergers and acquisitions.
(8) Includes the recovery of costs associated with plans to achieve specified energy savings goals.
(9) In connection with the December 2011 Nicor merger, we agreed to (i) not initiate a rate proceeding for Nicor Gas that would increase base rates prior to December 2014, (ii) maintain 2,070 full-time equivalent employees involved in the operation of Nicor Gas for a period of three years and (iii) maintain the personnel numbers in specific areas of safety oversight of the Nicor Gas system for a period of five years.

Current Regulatory Proceedings

Nicor Gas In June 2013, in connection with the PBR plan, the Illinois Commission issued an order requiring us to refund $72 million to current Nicor Gas customers through our PGA mechanism based upon natural gas throughput over 12 months beginning in July 2013. Approximately $43 million was refunded during 2014 and $29 million was refunded during 2013. For more information on the PBR plan, see Note 11 to our consolidated financial statements under Item 8 herein.

In August 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services, requesting refunds of $18 million and $22 million, respectively. We filed surrebuttal testimony in December 2014 disputing that any refund is due, as Nicor Gas was authorized to enter into these transactions and revenues associated with such reduced rate payer costs as either credits to the PGA or reductions to base rates were consistent with then-current Illinois Commission orders governing these activities. We believe these claims engage in hindsight speculation, which is expressly prohibited in a prudence review examination, and we intend to vigorously defend against these claims. Evidentiary hearings are scheduled for March 2015. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Nicor Gas' first three-year energy efficiency program, which outlines energy efficiency program offerings and therm reduction goals for a three-year period, ended in May 2014. Nicor Gas spent $125 million on the program and reduced customer usage by an estimated 46 million therms. Additionally, in May 2014, the Illinois Commission approved Nicor

Gas' second energy efficiency program, Energy Smart Plan, with expected spending of $93 million over a three-year period that began in June 2014. Nicor Gas spent $14 million on this new program in 2014.

Atlanta Gas Light In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. In September 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several Marketers that included a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. The Georgia Commission approved the stipulation in December 2014. Over the five-year period, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, will be used to resolve 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light is obligated to resolve 25% and we have recorded a reserve in our Consolidated Statements of Financial Position representing the future estimated cost to purchase the approximately 1.15 Bcf of natural gas. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all certificated Marketers through charges for system retained storage gas as it is used by the certificated Marketers.

In accordance with an order issued by the Georgia Commission, where AGL Resources makes a business acquisition that reduces the costs allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a ten-year period. In December 2013, we filed a Report of Synergy Savings with the Georgia Commission in connection with the Nicor acquisition. If and when approved, the net savings should result in annual rate reductions to the firm customers of Atlanta Gas Light of $5 million. We expect this filing to be discussed by the staff of the Georgia Commission in February 2015.

We expect Atlanta Gas Light to file a petition with the Georgia Commission for approval of a rate increase to our STRIDE surcharge associated with the final accounting of our pipeline replacement program (PRP) in February 2015. The proposed rate increase is designed to collect the unrecovered revenue requirement of the program and is in accordance with the requirements set forth by the Georgia Commission that allows Atlanta Gas Light to make a true-up filing at the end of the program to recover the actual costs of the program. The program ended December 31, 2013.

Virginia Natural Gas In April 2014, the Governor of Virginia signed into law legislation that enables the state's natural gas utilities, including Virginia Natural Gas, to acquire long-term supplies of natural gas and make capital investments to facilitate the delivery of low-cost shale and coal-bed methane gas to Virginia homeowners and businesses. Under the terms of the new statute, Virginia Natural Gas could enter into commercial agreements to obtain up to 25% of its annual firm sales demand for natural gas through long-term contracts or investments such as purchases of reserves. Recovery on investments would be based upon the utility's authorized return on rate base, which would flow through the PGA mechanism or a similar mechanism. The new statute also allows us to build pipelines and other infrastructure that deliver shale and coal-bed methane gas into the state's markets that seek to reduce natural gas supply costs or reduce price volatility for consumers. All filings under this legislation require approval by the Virginia Commission, and we have not made any filings to date.

Supply Six of our utilities use asset management agreements with our wholly owned subsidiary, Sequent, for the primary purpose of reducing our utility customers' gas cost recovery rates through payments to the utilities by Sequent. For Atlanta Gas Light, these payments are controlled by the Georgia Commission and utilized for infrastructure improvements and to fund heating assistance programs, rather than for a reduction to gas cost recovery rates. Under these asset management agreements, Sequent supplies natural gas to the utility and markets available pipeline and storage capacity to improve the overall cost of supplying gas to the utility customers. Currently, the utilities primarily purchase their gas from Sequent. The purchase agreements require Sequent to provide firm gas to our utilities. However, these utilities maintain the right and ability to make their own gas supply purchases. This right allows our utilities to make long-term supply arrangements if they believe it is in the best interest of their customers. Nicor Gas has not entered into an asset management agreement with Sequent or any other parties.

Each agreement with Sequent has either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without any annual minimum guarantee, or a fixed fee. From the inception of these agreements in 2001 through 2014, Sequent has made sharing payments under these agreements totaling $272 million. The following table provides payments made by Sequent to our utilities under these agreements during the last three years.

	Total amount received			
In millions	**2014**	**2013**	**2012**	**Expiration Date**
Elizabethtown Gas	$18	$6	$5	March 2019
Virginia Natural Gas	14	4	3	March 2016
Atlanta Gas Light	13	6	5	March 2017
Florida City Gas	1	1	1	(1)
Chattanooga Gas	1	1	1	March 2018
Total	$47	$18	$15	

(1) The term of the agreement is evergreen and renews automatically each year unless terminated by either party.

Transportation Our utilities use firm pipeline entitlements, storage services and/or peaking capacity contracted with interstate capacity providers to serve the firm natural gas supply needs of our customers. In addition, Nicor Gas, Atlanta

Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas operate on-system LNG facilities, underground natural gas storage fields and/or propane/air plants to meet the gas supply and deliverability requirements of their customers in the winter period. Generally, we work to build a portfolio of year-round firm transportation, seasonal storage and short-duration peaking services that will meet the needs of our customers under severe weather conditions with adequate operational flexibility to reliably manage the variability inherent in servicing customers using natural gas for space heating. Including seasonal storage and peaking services in this portfolio is more efficient and cost effective than reserving firm pipeline capacity rights all year for a limited number of cold winter days.

Our firm contracts range in duration from 3 to 25 years. We work to stagger terms to maintain our ability to adjust the overall portfolio to meet changing market conditions. Our utilities have contracted for capacity that is predominately sourced from producing areas in the midcontinent and gulf coast regions, and they continue to evaluate capacity options that will provide long-term access to reliable and affordable natural gas supplies. During 2014, we announced our participation in three pipeline projects that will provide access to shale gas in the proximity of our service territories. We have entered into longer-term contracts in connection with these pipeline projects, which resulted in an increase in the duration of our firm contracts compared to prior years. Given the number of agreements held by our utilities and the amount of capacity under contract, we make decisions as to the termination, extension or renegotiation of contracts every year.

Capital Projects

We continue to focus on capital discipline and cost control while moving ahead with projects and initiatives that we expect will have current and future benefits to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. Total capital expenditures incurred during 2014 for our distribution operations segment were $715 million. The following table and discussions provide updates on some of our larger capital projects under various programs at our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2015 are discussed in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity and Capital Resources."

	Program	**Program details**	**Recovery**	**Expenditures in 2014** (in millions)	**Expenditures since project inception** (in millions)	**Miles of pipe installed since project inception**	**Scope of program** (total miles)	**Program duration** (years)	**Last year of program**
Atlanta Gas Light	Integrated Vintage Plastic Replacement Program (i-VPR)	(1)	Rider	$62	$67	194	756	4	2017
Atlanta Gas Light	Integrated System Reinforcement Program (i-SRP)	(2)	Rider	13	264	n/a	n/a	8	2017
Atlanta Gas Light	Integrated Customer Growth Program (i-CGP)	(3)	Rider	7	47	n/a	n/a	8	2017
Chattanooga Gas	Bare Steel & Cast Iron	(4)	Rate Based	17	32	71	111	10	2020
Elizabethtown Gas	Aging Infrastructure Replacement (AIR)	(4)	Rider / Rate Based	32	38	40	130	4	2017
Elizabethtown Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort (ENDURE)	(5)	Rate Based	2	2	4	13	1	2015
Florida City Gas	Galvanized Replacement Program	(6)	Rate Based	1	14	75	111	17	2017
Nicor Gas	Investing in Illinois (Qualified Infrastructure)	(7) (8)	Rider	22	22	13	800	9	2023
Virginia Natural Gas	Steps to Advance Virginia's Energy (SAVE)	(7)	Rider	24	64	127	250	5	2017
	Total			$180	$550	524	2,171		

(1) Early vintage plastic, risk based mid vintage plastic, mid vintage neighborhood convenience.
(2) Large diameter pressure improvement and system reinforcement projects.
(3) New business construction and strategic line extension.
(4) Cast iron and bare steel.
(5) Cast iron and distribution reinforcement.
(6) Galvanized and X-Tube steel. Expenditures and miles reported are post AGL Resources acquisition.
(7) Cast iron, bare steel, mid vintage plastic and risk based materials.
(8) Represents expenditures on qualifying infrastructure that will be placed into service after the rate freeze date, December 9, 2014.

Atlanta Gas Light Our STRIDE program is comprised of i-SRP, i-CGP and i-VPR. STRIDE includes a surcharge on firm customers that provides recovery of the revenue requirement for the ongoing programs and the PRP, which ended on December 31, 2013. These infrastructure development, enhancement and replacement programs are used to update and expand distribution systems and liquefied natural gas facilities, improve system reliability and meet operational flexibility and growth. The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Under I-SRP, we must file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

A new $260 million, four-year STRIDE program was approved in December 2013, of which $214 million is for i-SRP related projects and $46 million is for i-CGP related projects. The program will be funded through a monthly rider surcharge per customer of $0.48 beginning in January 2015, which will increase to $0.96 beginning in January 2016 and to $1.43 beginning in January 2017. This surcharge will continue through 2025.

The purpose of the i-VPR program is to replace aging plastic pipe that was installed primarily in the mid-1960's to the early 1980's. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for replacement over the next 15 - 20 years as it reaches the end of its useful life. In 2013, the Georgia Commission approved i-VPR, which includes the replacement of the first 756 miles of vintage plastic pipe over four years for $275 million. The program is being funded through an increase in the STRIDE monthly rider surcharge per customer of $0.48 through December 2014, which increases to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016. This surcharge will continue through 2025. If the Georgia Commission elects to extend the i-VPR program beyond 2017, the remaining vintage plastic mains in our system could be considered for replacement through the program over the next 15 - 20 years as it reaches the end of its useful life. In December 2014, the Georgia Commission approved a stipulation between Atlanta Gas Light and the staff of the Georgia Commission that allows for the recovery or refund of certain operation and maintenance expenses associated with the i-VPR program that are above or below an established baseline amount of $7 million.

Nicor Gas In July 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average 4.0% of base rate revenues. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we may implement rates under the program effective in March 2015. Our filing included a project scope with cost estimates for three years of $171 million in 2015, $173 million in 2016 and $171 million in 2017. Our current project scope includes cost estimates that are approximately $200 million in 2015 and $250 million in each of 2016 and 2017. These expenditure levels represent approximately 1.3%, 3.5% and 4.0% of annual average base rate revenues for 2015, 2016 and 2017, respectively, which are all within the program requirements.

Elizabethtown Gas Our extension of the enhanced infrastructure program in 2013 allowed for infrastructure investment of $115 million over four years, effective as of September 2013, and is focused on the replacement of aging cast iron of our pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital (WACC) of 6.65%. We agreed to file a general rate case by September 2016. Prior accelerated infrastructure investments under this program will be recovered through a permanent adjustment to base rates.

In July 2014, the New Jersey BPU approved ENDURE, a program that will improve our distribution system's resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas will invest $15 million in infrastructure and related facilities and communication planning over a one year period from August 2014 through September 2015. The plan allows Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program.

Virginia Natural Gas The SAVE program, which was approved in August 2012, involves replacing aging infrastructure as prioritized through Virginia Natural Gas' distribution integrity management program. SAVE was filed in accordance with a Virginia statute providing a regulatory cost recovery mechanism for costs associated with certain infrastructure replacement programs. This five-year program includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering costs based on this program through a rate rider that became effective in August 2012. The second year performance rate update was approved by the Virginia Commission in July 2014 and became effective as of August 2014.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites. As we continue to conduct the MGP remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. These costs are primarily recovered through rate riders.

See Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Critical Accounting Policies and Estimates” and Note 3 to our consolidated financial statements under Item 8 herein for additional information about our environmental remediation liabilities and efforts.

Retail Operations

Our retail operations segment serves approximately 628,000 natural gas commodity customers and 1.2 million service contracts. Companies within our retail operations segment include SouthStar and Pivotal Home Solutions.

SouthStar is one of the largest retail natural gas marketers in the United States and markets natural gas to residential, commercial and industrial customers, primarily in Georgia and Illinois, where we capture spreads between wholesale and retail natural gas prices. Additionally, we offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. We charge a fee or premium for these services. Through our commercial operations, we optimize storage and transportation assets and effectively manage commodity risk, which enables us to maintain competitive retail prices and operating margin.

SouthStar is a joint venture owned 85% by us and 15% by Piedmont and is governed by an executive committee with equal representation by both owners. After considering the relevant factors, we consolidate SouthStar in our financial statements. See Note 10 to our consolidated financial statements under Item 8 herein for more information.

Pivotal Home Solutions provides a suite of home protection products and services that offer homeowners additional financial stability regarding their energy service delivery, systems and appliances. We offer a proprietary line of customizable home warranty and energy efficiency plans that can be co-branded with utility and energy companies. We have a portable product suite, which can be offered in most geographies and markets. Pivotal Home Solutions serves customers in several states, primarily Illinois, Indiana and Ohio. Additionally, we are working to expand product offerings to customers in our affiliate companies to enhance the customer experience and retention, as well as promote switching to natural gas from other energy products, such as electricity, propane or fuel oil.

Competition and Operations Our retail operations business competes with other energy marketers to provide natural gas and related services to customers in the areas in which they operate. In the Georgia market, SouthStar operates as Georgia Natural Gas and is the largest of 12 Marketers in the state, with average customers of nearly 500,000 over the last three years and market share of approximately 31% during 2014.

In recent years, increased competition and the heavy promotion of fixed-price plans by SouthStar’s competitors have resulted in increased pressure on retail natural gas margins. In response to these market conditions, SouthStar’s residential and commercial customers have been migrating to fixed-price plans, which, combined with increased competition from other Marketers, has impacted SouthStar’s customer growth as well as margins. However, SouthStar has utilized new products and marketing partnerships to stabilize its portfolio mix in Georgia and has entered new retail markets to position the company for future growth.

In addition, similar to our natural gas utilities, our retail operations businesses face competition based on customer preferences for natural gas compared to other energy products, primarily electricity, and the comparative prices of those products. We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers.

SouthStar’s operations are sensitive to seasonal weather, natural gas prices, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar’s retail pricing strategies and the use of a variety of hedging strategies, such as the use of futures, options, swaps, weather derivative instruments and other risk management tools, help to ensure retail customer costs are covered to mitigate the potential effect of these issues and commodity price risk on its operations. For more information on SouthStar’s energy marketing and risk management activities, see Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Natural Gas Price Risk.”

Our retail operations business also experiences price, convenience and service competition from other warranty and HVAC companies. These businesses also bear risk from potential changes in the regulatory environment.

Wholesale Services

Our wholesale services segment consists of our wholly owned subsidiary, Sequent, which engages in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the U.S. and Canada. Wholesale services utilizes a portfolio of natural gas storage assets, contracted supply from all of the major producing regions, as well as contracted storage and transportation capacity to provide these services to its customers. Its customers consist primarily of electric and natural gas utilities, power generators and large industrial customers. Our logistical expertise enables us to provide our customers with natural gas from the major producing regions and market hubs. We also leverage our portfolio of natural gas storage assets and contracted natural gas supply, transportation and storage capacity to meet our delivery requirements and customer obligations at competitive prices.

Wholesale services' portfolio of storage and transportation capacity enables us to generate additional operating margin by optimizing the contracted assets through the application of our wholesale market knowledge and risk management skills as opportunities arise. These asset optimization opportunities focus on capturing the value from idle or underutilized assets, typically by participating in transactions that take advantage of volatility in pricing differences between varying geographic locations and time horizons (location and seasonal spreads) within the natural gas supply, storage and transportation markets to generate earnings. We seek to mitigate the commodity price and volatility risks and protect our operating margin through a variety of risk management and economic hedging activities.

In May 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers. Under the terms of the purchase and sale agreement, we received an initial cash payment of $12 million, resulting in a pre-tax gain of $11 million ($5 million net of tax) and were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received a cash payment of $4 million, resulting in the recognition of a $3 million gain. We have a five-year agreement through April 2018 to supply natural gas to our former customers.

Competition and operations Wholesale services competes for asset management, long-term supply and seasonal peaking service contracts with other energy wholesalers, often through a competitive bidding process. We are able to price competitively by utilizing our portfolio of contracted storage and transportation assets and by renewing and adding new contracts at prevailing market rates. We will continue to broaden our market presence where our portfolio of contracted storage and transportation assets provides us a competitive advantage, as well as continue our pursuit of additional opportunities with power generation companies and natural gas producers located in the areas of the country in which we operate. We are also focused on building our fee-based services as a source of operating margin that is less impacted by volatility in the marketplace.

We view our wholesale margins from two perspectives. First, we base our commercial decisions on economic value for both our natural gas storage and transportation transactions. For our natural gas storage transactions, economic value is determined based on the net operating revenue to be realized at the time the physical gas is withdrawn from storage and sold and the derivative instrument used to economically hedge natural gas price risk on the physical storage is settled. Similarly, for our natural gas transportation transactions, economic value is determined based on the net operating revenue to be realized at the time the physical gas is purchased, transported, and sold utilizing our transportation capacity along with the settlement value associated with any derivative instruments.

The second perspective is the values reported in accordance with GAAP and encompassing periods prior to and in the period of physical withdrawal and sale of inventory or purchase, transportation and sale of natural gas. We enter into derivatives to hedge price risk prior to when the related physical storage withdrawal or transportation transactions occur based upon our commercial evaluation of future market prices. The reported GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value and prior to the period the related physical storage and transportation transactions occur and are recognized in earnings. The change in fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. This results in reported earnings volatility during the interim periods; however, the expected margin based upon the hedged economic value is ultimately realized in the period natural gas is physically withdrawn from storage or transported and sold at market prices and the related hedging instruments are settled.

For our natural gas storage portfolio, we purchase natural gas for storage when the current market price we pay plus the cost for transportation, storage and financing is less than the market price we anticipate we could receive in the future. We attempt to mitigate substantially all of the commodity price risk associated with our storage portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or OTC derivatives in forward months to substantially protect the operating revenue that we will ultimately realize when the stored gas is actually sold.

Our natural gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge natural gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs.

Midstream Operations

Our midstream operations segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets in the Gulf Coast region of the U.S. and in northern California. While this business can generate additional revenue during times of peak market demand for natural gas storage services, our natural gas storage facilities have a portfolio of short, medium and long-term contracts at fixed market rates. In addition to natural gas storage, this segment also includes our developing LNG business, which focuses on LNG for transportation, and select pipeline investments that are outside of state regulatory jurisdiction.

Pipelines During 2014, we entered into three pipeline agreements, as indicated in the following table, which are subject to regulatory approvals. These projects, along with our existing pipelines discussed below, will support our efforts to provide diverse sources of natural gas supplies to our customers, resolve current and long-term supply planning for new capacity, enhance system reliability and generate economic development in the areas served. The pipeline development projects will be financed through a combination of commercial paper and long-term debt issuances. See Note 10 to the consolidated financial statements under Item 8 herein for additional information.

Dollars in millions	**Miles of pipe**	**Expected capital expenditures** (1)	**Ownership interest** (1)	**Scheduled year of completion**	**Expected FERC filing process** File date	Approval date
Dalton Pipeline (2)	106	$210	50%	2017	2015	2016
PennEast Pipeline (3)	108	200	20%	2017	2015	2016
Atlantic Coast Pipeline (4)	550	260	5%	2018	2015	2016
Total	764	$670				

(1) Represents our expected capital expenditures and ownership interest, which may change.
(2) In April 2014, we entered into two agreements associated with the construction of the Dalton Lateral Pipeline, which will serve as an extension of the Transco pipeline system and provide additional natural gas supply to our customers in Georgia. The first is a construction and ownership agreement and the second is an agreement to lease our ownership in this lateral pipeline extension once it is placed in service.
(3) In August 2014, we entered into a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to our customers in New Jersey. We believe this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during the past winter.
(4) In September 2014, we entered into a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to our customers in Virginia.

Magnolia Enterprise Holdings, Inc. This wholly owned subsidiary operates a pipeline that provides our Georgia customers diversification of natural gas sources and increased reliability of service in the event that supplies coming from other supply sources are disrupted.

Horizon Pipeline This 50% owned joint venture with Natural Gas Pipeline Company of America operates an approximate 70 mile natural gas pipeline stretching from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas has contracted for approximately 80% of Horizon Pipeline's total throughput capacity of 0.38 Bcf under an agreement expiring in May 2025.

Competition and operations Our natural gas storage facilities primarily compete with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Salt caverns have also been leached from bedded salt formations in the Northeastern and Midwestern states. Competition for our Central Valley storage facility primarily consists of storage facilities in northern California and western North America.

The market fundamentals of the natural gas storage business are cyclical. The abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. In 2014, expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to continue in 2015 as compared to historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy continues to improve, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. We believe our storage assets are strategically located to benefit from these expected improvements in market fundamentals, including the overall growth in the natural gas market, and there are significant barriers to developing new storage facilities, including construction time and other costs, federal, state and local permitting and approvals and suitable and available sites, to capitalize on these expected improvements in market conditions.

Other

Our "other" non-reportable segment includes aggregated subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our reportable segments. This segment includes our investment in Triton, which was not part of the sale of Tropical Shipping that closed on September 1, 2014. See Note 14 to the consolidated financial statements under Item 8 herein for additional information on the disposition of Tropical Shipping. AGL Services Company is a service company we established to provide certain centralized shared services to our reportable segments. We allocate substantially all of AGL Services Company's operating expenses and interest costs to our reportable segments in accordance with state regulations. Our EBIT results include the impact of these allocations to the various reportable segments.

AGL Capital, our wholly owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt instruments and other financing arrangements.

Employees

As of December 31, 2014, we had approximately 5,165 employees, all of whom were in the U.S. The decrease in total employees from 2013 primarily resulted from the sale of our Tropical Shipping business in 2014. The following table provides information about our natural gas utilities' collective bargaining agreements, which represent approximately 33% of our total employees.

	Number of employees	Contract expiration date
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19) (1)	1,386	February 2017
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50) (2)	139	May 2015
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	171	November 2015
Total	1,696	

(1) Nicor Gas' collective bargaining agreement expired in February 2014, and a new agreement was ratified in April 2014. The new agreement provides for additional operational enhancements and changes to certain benefits, but does not have a material effect on our consolidated financial statements.

(2) Contract negotiations are ongoing; however, we do not expect a new contract to be finalized prior to the expiration of the current contract. We have a continuation agreement in place and do not expect this to result in a work stoppage.

We believe that we have a good working relationship with our unionized employees and there have been no work stoppages at Virginia Natural Gas, Elizabethtown Gas, or Nicor Gas since we acquired those operations in 2000, 2004, and 2011, respectively. As we have done historically, we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the company and our employees. Our current collective bargaining agreements do not require our participation in multiemployer retirement plans and we have no obligation to contribute to any such plans.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and proxy statements, and amendments to those reports that we file with, or furnish to, the SEC are available free of charge at the SEC website http://www.sec.gov and at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with, or furnish such reports to, the SEC. However, our website and any contents thereof should not be considered to be incorporated by reference into this document. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations
P.O. Box 4569
Atlanta, GA 30302-4569
404-584-4000

In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for our 2015 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 17, 2015, and we will make it available on our website as soon as reasonably practicable thereafter. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each committee of our Board of Directors are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

ITEM 1A. RISK FACTORS

Forward-Looking Statements

This report and the documents incorporated by reference herein contain "forward-looking statements." These statements, which may relate to such matters as future earnings, growth, liquidity, supply and demand, costs, subsidiary performance, credit ratings, dividend payments, new technologies and strategic initiatives, often include words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "proposed," "seek," "should," "target," "would" or similar expressions. You are cautioned not to place undue reliance on forward-looking statements. While we believe that our expectations are reasonable in view of the information that we currently have, these expectations are subject to future events, risks and uncertainties, and there are numerous factors—many beyond our control—that could cause actual results to vary materially from these expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation, including any changes related to climate matters; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, and unexpected changes in project costs, including the cost of funds to finance these projects and our ability to recover our project costs from our customers; limits on pipeline capacity; the impact of acquisitions and divestitures, including recent acquisitions in our retail operations segment; our ability to successfully integrate operations that we have or may acquire or develop in the future; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment; general economic conditions; uncertainties about environmental issues and the related impact of such issues, including our environmental remediation plans; the impact of the new depreciation rates for Nicor Gas; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters, such as hurricanes, on the supply and price of natural gas; acts of war or terrorism; the outcome of litigation; and the factors described in this Item 1A, “Risk Factors” and the other factors discussed in our filings with the SEC.

There also may be other factors that we do not anticipate or that we do not recognize are material that could cause results to differ materially from expectations. Forward-looking statements speak only as of the date they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required by law.

Risks Related to Our Business

Our business is subject to substantial regulation by federal, state and local regulatory authorities. Adverse determinations by them and, in some instances, the absence of timely determinations, could adversely affect our business.

At the federal level, our business is regulated by the FERC. At the state level, our business is regulated by public service commissions or similar authorities, as well as local governing bodies with respect to certain issues.

Depending upon the jurisdiction, these regulatory authorities are generally entitled to review and approve many aspects of our operations, including the rates that we charge customers (including the recovery of costs for pipeline replacement and other capital projects), the rates of return on our equity investments in our operating companies, how we operate our business, and the interaction between our regulated operating companies and other subsidiaries that might provide products or services to those companies. In addition, our operating companies are generally subject to franchise agreements that entitle them to provide products and services.

While applicable law often provides a framework for the approvals that we need, the regulatory authorities generally have broad discretion. Moreover, in some jurisdictions, the regulatory process involves elected officials and is subject to inherent political issues, which can impact the approvals that we request. As a result, we may or may not be able to obtain the approvals that we request, the timing of obtaining those approvals can be uncertain, and the approvals can be subject to conditions that may or may not be favorable to our business. Should we not be able to obtain the rate increases that we request in a timely manner, should we not be able to fully recover the costs that we incur, or should we otherwise not obtain favorable approvals for the operation of our business, our business will be adversely impacted.

In addition, the regulatory environment in which we operate has increased in complexity over time, and further change is likely in many jurisdictions. These changes may or may not be favorable to our business. As the regulatory environment grows in complexity, inadvertent noncompliance is increasingly a greater risk. Noncompliance can, depending upon the circumstances, result in fines, penalties or other enforcement action by regulatory authorities, as well as damage our reputation and standing in the community, all of which would adversely impact our business.

Energy prices can fluctuate widely and quickly. To the extent that we have not anticipated and planned for those changes, our business can be adversely affected.

Recently, the price for natural gas and competing energy sources, such as oil, have fluctuated widely. Generally, we pass through changes in prices to the customers of our operating companies, and we have a process in place to continually review the adequacy of our utility gas rates and to take appropriate action with the applicable regulatory authorities. However, there is an inherent regulatory lag in adjusting rates and, in an increasing price environment, we have to bear the increased costs on an interim basis. We also have to incur additional financing costs as a result of purchasing more expensive gas.

In addition, increases in gas prices, both in absolute terms and relative to alternative energy sources, negatively impacts demand, the ability of customers to pay their utility bills and the timing of those payments (which lead to larger accounts receivable and greater bad debt expense) and various other factors. While the impact of some of these factors can be passed through to customers, there is generally a delay in that process that can adversely affect our business.

As noted below, for some portions of our business, we hedge the risk of price changes through the purchase of futures contracts and other means. These efforts, while designed to minimize the adverse impact of price changes, cannot assure that result. As a result, we retain exposure to price changes that can, in a volatile energy market, be extremely material and can adversely affect our business.

Variations in weather beyond what we have planned for can adversely impact our business.

A substantial portion of our revenue is derived from the transportation or sale of gas for space heating purposes. We plan for the demand of gas for this purpose based upon historical weather patterns and resulting demand. Where weather varies significantly beyond the range that we have planned for, it can impact us in many ways, including through increasing or decreasing the demand for gas, the cost of gas to us, and the availability, sufficiency and cost of transportation and storage capacity.

A decrease in the availability of adequate pipeline transportation capacity due to weather conditions or otherwise could adversely impact our business. We depend upon having access to adequate transportation and storage capacity for virtually all of our operations. A decrease in interstate pipeline capacity available to us, or an increase in competition for interstate pipeline transportation and storage capacity (e.g., even as a result of weather in regions that we do not significantly serve) could reduce our normal interstate supply of gas or cause rates to fluctuate.

We have WNA mechanisms for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas that partially offset the impact of unusually cold or warm weather on residential and commercial customer billings and on our operating margin, although at Elizabethtown Gas, we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10.3%. These WNA regulatory mechanisms are most effective in a reasonable temperature range relative to normal weather using historical averages. Outside of those ranges, our financial exposure is greater.

We also have decoupled rate designs, including straight-fixed-variable, at Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas that allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers. For more information, see Item 1, "Business" under the caption "Rate Structures" herein.

At Nicor Gas, approximately 60% of all usage is for space heating and approximately 75% of the usage and revenues occur from October through March. Weather fluctuations have the potential to significantly impact operating income and cash flow. For example, we estimate that a 100 degree-day variation from normal weather of 5,752 Heating Degree Days impacts Nicor Gas' margin, net of income taxes, by approximately $1 million under its current rate structure. For our weather risk associated with Nicor Gas, we utilize weather derivatives to reduce, but not eliminate, the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois. For more information, see Note 2 to the consolidated financial statements under Item 8 herein.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to mitigate the impact on its operating margin in the event of warmer or colder-than-normal weather in the winter months. However, these instruments do not fully mitigate the effects of unusually warm or cold weather.

Similarly, changes in weather conditions may also impact wholesale services' earnings. In addition to the impacts described above, weather impacts the ability of our wholesale services segment to capture value from location and seasonal spreads. Through the acquisition of natural gas and hedging of natural gas prices, wholesale services reduces some of the weather-related risks that it faces, but it cannot eliminate all of those risks.

Our retail energy businesses in Illinois, Nicor Solutions and Nicor Advanced Energy, offer utility-bill management products that mitigate and/or eliminate the risks of variations in weather to customers. We hedge this risk to reduce any adverse effects to us from weather variations.

We are subject to environmental regulation and our costs to comply are significant. Any changes in existing environmental regulation could adversely affect our business.

We are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations associated with storage, transportation, treatment and disposal of MGP residuals and waste in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to material fines, penalties or interruptions in our operations.

We are generally responsible for liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available, we manufactured gas from coal and other fuels. Those manufacturing operations were known as MGPs, which we ceased operating in the 1950s. A number of environmental issues may exist with respect to MGP's. For more information regarding these obligations, see Note 11 to the consolidated financial statements under Item 8 herein. Claims against us under environmental laws and regulations could result in material costs and liabilities.

Existing environmental laws and regulations could also be revised or reinterpreted, and new laws and regulations could be adopted or become applicable to us or our facilities. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties that could have a material adverse effect on our business.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions and replacements to our natural gas distribution systems to continue the expansion of our customer base and improve system reliability, especially during peak usage. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of such construction may be affected by the cost of obtaining government and other approvals, project delays, adequacy of supply of vendors, vendor performance, or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, the projected construction schedule and the completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of such construction. As a result, we may be required to fund a portion of our cash needs through borrowings, the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or it may impair our ability to complete the expansions or development projects.

We may be exposed to regulatory and financial risks related to the impact of climate change and associated legislation and regulation.

Climate change is expected to receive increasing attention from the current federal administration, non-governmental organizations and legislators. Debate continues as to the extent to which our climate is changing, the potential causes of any change and its potential impacts. Some attribute climate change to increased levels of greenhouse gases, including carbon dioxide and methane, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

The EPA has begun using provisions of the Clean Air Act to regulate greenhouse gas emissions, including carbon dioxide and methane, differently than under historical precedent. Thus far, EPA has imposed greenhouse gas regulations on automobiles and implemented new permitting requirements for the construction or modification of major stationary sources of greenhouse gas emissions, including natural gas-fired power plants.

In addition, President Obama issued a Presidential Memorandum on June 25, 2013, directing the EPA to adopt performance standards to regulate greenhouse gas emissions from power plants. Specifically, the Presidential Memorandum directs the EPA to propose standards for future power plants by September 20, 2013 and propose regulations and emission guidelines for modified, reconstructed, and existing power plants by June 1, 2014. The Presidential Memorandum directs the EPA to finalize those regulations by June 1, 2015. States would be required to develop regulations implementing the EPA’s guidelines by June 30, 2016. It also includes a wide variety of other initiatives designed to reduce greenhouse gas emissions, prepare for the impacts of climate change, and lead international efforts to address climate change.

The outcome of federal and state actions to address climate change could potentially result in new regulations, additional charges to fund energy efficiency activities or other regulatory actions, which in turn could:

- result in increased costs associated with our operations,
- increase other costs to our business,
- affect the demand for natural gas (positively or negatively), and
- impact the prices we charge our customers and affect the competitive position of natural gas.

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

Any adoption of regulation by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on our business.

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

Our gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, including explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected, which may limit our ability to grow our business.

The natural gas business is highly competitive, increasingly complex, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our retail businesses is affected by competition from other energy marketers providing retail natural gas services in our service territories, most notably in Illinois and Georgia. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher natural gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our retail operations segment markets fixed-price and fixed-bill contracts that protect customers against higher natural gas prices, or protect customers against both higher natural gas prices and colder weather. The sale of these fixed-price contracts may be adversely affected if natural gas prices are, or are perceived to be, low and stable. Our retail operations segment also faces risks in the form of price, convenience and service competition from other warranty and HVAC companies.

Our wholesale services segment competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on our ability to aggregate competitively-priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our operating margin. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related operating margin available in this portion of Sequent’s business.

Our midstream operations segment competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Competition for our Central Valley storage facility in northern California primarily consists of storage facilities in northern California and western North America. Storage values have declined over the past several years due to low gas prices and low volatility, and we expect this to continue in 2015.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk at Nicor Gas, Atlanta Gas Light, SouthStar and Sequent.

Nicor Gas and Sequent often extend credit to counterparties. Despite performing credit analyses prior to extending credit and seeking to implement netting agreements, if the counterparties fail to perform and any collateral Nicor Gas or Sequent has secured is inadequate, we could experience material financial losses.

Further, Sequent has a concentration of credit risk with a limited number of parties. Most of this concentration is with counterparties that are either load-serving utilities or end-use customers that have supplied some level of credit support. Default by any of these counterparties in their obligations to pay amounts due to Sequent could result in credit losses that could be significant.

We have accounts receivable collection risks in Georgia due to a concentration of credit risks related to the provision of natural gas services to approximately 12 Marketers. As a result, Atlanta Gas Light depends on a limited number of customers for a significant portion of its revenues.

Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers’ bills and, consequently, impair customers’ ability to pay. For more information, see Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Credit Risk” herein.

The asset management arrangements between Sequent and our LDC’s, and between Sequent and its non-affiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent’s business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas and Elkton Gas. The profits it earns from the management of those assets with these affiliates are shared with their respective customers and for Atlanta Gas Light with the Georgia Commission’s Universal Service Fund, with the exception of Chattanooga Gas and Elkton Gas where Sequent is assessed annual fixed-fees. Entry into and renewal of these agreements are subject to regulatory approval, and we cannot predict whether such agreements will be renewed or the terms of such renewal.

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

We are exposed to market risk and may incur losses in wholesale services, midstream operations and retail operations.

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at midstream operations and SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. For more information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "VaR" herein.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect for wholesale services.

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were initiated.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the performance of investments, demographics, and various other factors and assumptions. These changes may have a material adverse effect on us.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics and assumptions, including longer life expectancy of beneficiaries and changes in health care cost trends. Any sustained declines in equity markets and reductions in bond yields will have an adverse effect on the value of our pension plan assets. In these circumstances, we may be required to recognize an increased pension expense and a charge to our other comprehensive income to the extent that the actual return on assets in the pension fund is less than the expected return. We may be required to make additional contributions in future periods in order to preserve the current level of benefits under the plans and in accordance with federal funding requirements.

For more information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Contractual Obligations and Commitments" and the subheading "Pension and Welfare Obligations" and Note 6 to the consolidated financial statements under Item 8 herein.

Natural disasters, terrorist activities and similarly unpredictable events could adversely affect our businesses.

Natural disasters may damage our assets, interrupt our business operations and adversely impact the demand for natural gas. Future acts of terrorism could be directed against companies operating in the U.S., and companies in the energy industry may face a heightened risk of exposure. The insurance industry has been disrupted by these types of events. As a result, the availability of insurance covering risks against which we and similar businesses typically insure may be limited or insufficient. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms. In addition, an employee or third party may purposely, or inadvertently, fail to adhere to our policies and procedures or our policies and procedures may not be effective; this could result in the violation of a law or regulation, a material error or misstatement, damage to our reputation or the incurrence of substantial expense.

Work stoppages could adversely impact our businesses.

Some of our businesses are dependent upon employees who are represented by unions and are covered by collective bargaining agreements. These agreements may increase our costs, affect our ability to continue offering market-based salaries and benefits, and limit our ability to implement efficiency-related improvements. Disputes with the unions could result in work stoppages that could impact the delivery of natural gas and other services, which could strain relationships with customers, vendors and regulators. We believe that we have a good working relationship with our unionized employees and we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the company and our employees. For more information, see Item 1, "Business" under the caption "Employees" herein.

Changes in laws and regulations regarding the sale and marketing of products and services offered by our retail operations segment could adversely affect our results of operations, cash flows and financial condition.

Our retail operations segment provides various energy-related products and services. These include sales of natural gas and utility-bill management services to residential and small commercial customers, and the sale, repair, maintenance and warranty of heating, air conditioning and indoor air quality equipment. The sale and marketing of these products and services are subject to various state and federal laws and regulations. Changes in these laws and regulations could impose additional costs on, restrict or prohibit certain activities, which could adversely affect our results of operations, cash flows and financial condition.

Conservation could adversely affect our results of operations, cash flows and financial condition.

As a result of legislative and regulatory initiatives on energy conservation, we have put into place programs to promote additional energy efficiency by our customers. Funding for such programs is being recovered through cost recovery riders. However, the adverse impact of lower deliveries and resulting reduced margin could adversely affect our results of operations, cash flows and financial condition.

A security breach could disrupt our operating systems, shutdown our facilities or expose confidential personal information.

Security breaches of our information technology infrastructure, including cyber-attacks, could lead to system disruptions or generate facility shutdowns. If a cyber-attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, a cyber-attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

Additionally, the protection of customer, employee and company data is critical to us. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and could expose us to liability to our customers, vendors, financial institutions and others. In addition, a breakdown or breach could also materially increase the costs we incur to protect against such risks. There is no guarantee that the procedures that we have implemented to protect against unauthorized access to secured data are adequate to safeguard against all data security breaches, although, to our knowledge, we did not have any material security breaches in 2014.

We may pursue acquisitions, divestitures and other strategic transactions, the success of which may impact our results of operations, cash flows and financial condition.

We have pursued acquisitions to complement or expand our business, divestures and other strategic transactions in the past and expect to in the future. If we identify an acquisition candidate, we may not be able to successfully negotiate or finance the acquisition or integrate the acquired businesses with our existing business and services. Acquisitions may result in dilutive issuances of equity securities and the incurrence of debt and contingent liabilities, amortization expenses and substantial goodwill. Acquisitions may not be accretive to our earnings and may cause dilution to our earnings per share, which may negatively affect the market price of our common shares. Any failure to successfully integrate businesses that we acquire in an efficient and effective manner could have a material adverse effect on us. Similarly, we may divest portions of our business, which may also have material and adverse effects.

We assess goodwill for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. We assess our long-lived assets, including finite-lived intangible assets, for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. To the extent the value of goodwill or long-lived assets become impaired, we may be required to incur impairment charges that could have a material impact on our results of operations. No impairment of goodwill was recorded as a result of our 2014 annual impairment testing, as the fair value of each reporting unit was in excess of the carrying value. Additionally, no impairment of long-lived assets was recorded during 2014.

Since interest rates are a key component, among other assumptions, in the models used to estimate the fair values of our reporting units, as interest rates rise, the calculated fair values decrease and future impairments may occur. Further, the rates for contracting capacity at Jefferson Island, Golden Triangle and Central Valley are also key components in the models used to estimate their fair value. Consequently, a further decline in market fundamentals and the rates for contracting availability could result in future impairments. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, we cannot provide assurance that future analyses will not result in impairment. These assumptions and estimates include projected cash flows, current and future rates for contracted capacity, growth rates, WACC and market multiples. For additional information, see Item 7,"Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Critical Accounting Policies and Estimates" herein.

Risks Related to Our Corporate and Financial Structure

We depend on access to the capital and financial markets to fund our business. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.

We rely on access to both short-term money markets (in the form of commercial paper and lines of credit) and long-term capital markets as sources of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be negatively affected, and we may be forced to postpone, modify or cancel capital projects. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from:

- adverse economic conditions;
    - adverse general capital market conditions;
    - poor performance and health of the utility industry in general;
    - bankruptcy or financial distress of unrelated energy companies or marketers;

- significant decrease in the demand for natural gas;
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business;
- terrorist attacks on our facilities or our suppliers; or
- extreme weather conditions.

The amount of our working capital requirements in the near term will primarily depend on the market price of natural gas and weather. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations.

While we believe we can meet our capital requirements from our operations and our available sources of financing, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near term. The future effects on our business, liquidity and financial results due to market disruptions could be material and adverse to us, both in the ways described above or in ways that we do not currently anticipate.

A downgrade in our credit rating would require us to pay higher interest rates and could negatively affect our ability to access capital, or may require us to provide additional collateral to certain counterparties.

Our senior debt is currently assigned investment grade credit ratings. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we would be required to provide additional collateral to continue conducting business with certain customers. For additional credit rating and interest rate information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity and Capital Resources" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" herein.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense and adversely affect our earnings.

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. For additional information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" herein. However, we may not structure these swap agreements in a manner that manages our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

We are a holding company and are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need.

A significant portion of our outstanding debt was issued by our wholly owned subsidiary, AGL Capital, which we fully and unconditionally guarantee. Since we are a holding company and have no operations separate from our investment in our subsidiaries, we are dependent on the net income and cash flows of our subsidiaries and their ability to pay upstream dividends or other distributions to meet our financial obligations and to pay dividends on our common stock. The ability of our subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. In addition, Nicor Gas is not permitted to make money pool loans to affiliates. Refer to Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" herein for additional information.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivative instruments, including futures, options, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In addition, derivative contracts entered into for hedging purposes may not offset 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 derivative instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the reported fair values of these contracts.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.

Our credit facilities contain cross-default provisions. Should an event of default occur under some of our debt agreements, we face the prospect of being in default under our other debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

ITEM 2. PROPERTIES

We consider our properties to be well maintained, in good operating condition and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by our segments. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 8 to our consolidated financial statements under Item 8 herein.

Distribution and transmission mains

Our distribution systems transport natural gas from our pipeline suppliers to customers in our service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters and regulators. At December 31, 2014, our distribution operations segment owned approximately 80,700 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair, and believe that our distribution systems are in good condition.

Storage assets

Distribution Operations We own and operate eight underground natural gas storage facilities in Illinois with a total inventory capacity of about 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. The system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of its normal winter deliveries in Illinois. This level of storage capability provides us with supply flexibility, improves the reliability of deliveries and can help mitigate the risk associated with seasonal price movements.

We have five LNG plants located in Georgia, New Jersey and Tennessee with LNG storage capacity of approximately 7.6 Bcf. In addition, we own one propane storage facility in Virginia with a storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by our distribution operations segment to supplement natural gas supply during peak usage periods.

Midstream Operations We own three high-deliverability natural gas storage and hub facilities that are operated by our midstream operations segment. Jefferson Island operates a storage facility in Louisiana currently consisting of two salt dome gas storage caverns. Golden Triangle operates a storage facility in Texas consisting of two salt dome caverns. Central Valley operates a depleted field storage facility in California. In addition, we have an LNG facility in Alabama that produces LNG for Pivotal LNG, a wholly owned subsidiary, to support its business of selling LNG as a substitute fuel in various markets. For additional information on our storage facilities, see Item 1, "Business" under the caption "Midstream Operations" herein.

Offices

All of our reportable segments own or lease office, warehouse and other facilities throughout our operating areas. We expect additional or substitute space to be available as needed to accommodate the expansion of our operations.

ITEM 3. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party as both plaintiff and defendant to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations.

For more information regarding our regulatory proceedings and litigation, see Note 11 to our consolidated financial statements under the caption "Litigation" under Item 8 herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the ticker symbol GAS. At February 4, 2015, there were 21,551 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2014 and 2013 is as follows:

Quarter ended:	Sales price of common stock High	Sales price of common stock Low	Cash dividend per common share
March 31, 2014	$49.84	$45.17	$0.49
June 30, 2014	55.10	48.29	0.49
September 30, 2014	55.30	48.72	0.49
December 31, 2014	56.67	50.10	0.49
			$1.96

Quarter ended:	Sales price of common stock High	Sales price of common stock Low	Cash dividend per common share
March 31, 2013	$42.37	$38.86	$0.47
June 30, 2013	44.85	41.21	0.47
September 30, 2013	47.00	41.94	0.47
December 31, 2013	49.31	44.56	0.47
			$1.88

We have paid 268 consecutive quarterly dividends to our common shareholders beginning in 1948, historically four times each year: March 1, June 1, September 1 and December 1. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Cash Flow from Financing Activities - Dividends on Common Stock" herein. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants, and
- our ability to satisfy our obligations to any future preferred shareholders.

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

- we could not pay our debts as they become due in the usual course of business, or
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy (upon dissolution) the preferential rights of shareholders whose rights are superior to those of the shareholders receiving the dividends.

Issuer Purchases of Equity Securities

There were no purchases of our common stock by us or any affiliated purchasers during the three months ended December 31, 2014.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below which should be read in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data" herein. Additionally, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein for a discussion of the primary factors impacting the changes in our results of operations for the periods reflected in our Consolidated Statements of Income. The operations of our former Tropical Shipping business, which was sold during 2014, are reflected as discontinued operations and all prior periods have been recast to reflect the discontinued operations. Material changes from 2013 to 2014 are due primarily to earnings from our wholesale services segment, resulting mainly from colder-than-normal weather and associated natural gas price volatility in 2014. Material changes from 2011 to 2012 are primarily due to the Nicor merger, which closed on December 9, 2011.

Dollars and shares in millions, except per share amounts	**2014**	**2013**	**2012**	**2011**	**2010**
Income statement data					
Operating revenues	$5,385	$4,209	$3,562	$2,305	$2,373
Operating expenses					
Cost of goods sold	2,765	2,110	1,583	1,085	1,164
Operation and maintenance (1)	939	887	816	497	497
Depreciation and amortization	380	397	394	182	160
Nicor merger expenses (1)	-	-	20	57	6
Taxes other than income taxes	208	187	159	57	46
Total operating expenses	4,292	3,581	2,972	1,878	1,873
Gain on disposition of assets	2	11	-	-	-
Operating income	1,095	639	590	427	500
Other income (expense)	14	16	24	7	(1)
EBIT	1,109	655	614	434	499
Interest expense, net	179	170	183	134	109
Income before income taxes	930	485	431	300	390
Income tax expense	350	177	157	121	140
Income from continuing operations	580	308	274	179	250
(Loss) income from discontinued operations, net of tax	(80)	5	1	-	-
Net income	500	313	275	179	250
Less net income attributable to the noncontrolling interest	18	18	15	14	16
Net income attributable to AGL Resources Inc.	$482	$295	$260	$165	$234
Amounts attributable to AGL Resources Inc.					
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259	$165	$234
(Loss) income from discontinued operations, net of tax	(80)	5	1	-	-
Net income attributable to AGL Resources Inc.	$482	$295	$260	$165	$234
Per common share information					
Diluted weighted average common shares outstanding	119.2	118.3	117.5	80.9	77.8
Diluted earnings (loss) per common share					
Continuing operations	$4.71	$2.45	$2.20	$2.04	$3.00
Discontinued operations	(0.67)	0.04	0.01	-	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21	$2.04	$3.00
Dividends declared per common share	$1.96	$1.88	$1.74	$1.90	$1.76
Dividend payout ratio	49%	76%	79%	93%	58%
Dividend yield (2)	3.6%	4.0%	4.4%	4.5%	4.9%
Price range:					
High	$56.67	$49.31	$42.88	$43.69	$40.08
Low	$45.17	$38.86	$36.59	$34.08	$34.21
Close (3)	$54.51	$47.23	$39.97	$42.26	$35.85
Market value (3)	$6,522	$5,615	$4,711	$4,946	$2,800
Statements of Financial Position data (3)					
Total assets (4)	$14,909	$14,550	$14,070	$13,862	$7,481
Property, plant and equipment – net	9,090	8,643	8,205	7,741	4,396
Long-term debt	3,802	3,813	3,553	3,578	1,971
Total equity	3,828	3,613	3,391	3,305	1,809
Financial ratios (3)					
Debt	57%	58%	59%	60%	60%
Equity	43%	42%	41%	40%	40%
Total	100%	100%	100%	100%	100%
Return on average equity	13.0%	8.4%	7.8%	6.4%	12.9%

(1) Transaction expenses associated with the Nicor merger were excluded from operation and maintenance expenses and presented separately.
(2) Dividends declared per common share during the fiscal period divided by market value per common share as of the last day of the fiscal period.
(3) As of the last day of the fiscal period.
(4) Amounts for all periods include assets held for sale, which reflect the assets of our former Tropical Shipping business.

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

Executive Summary

We are an energy services holding company whose principal business is the distribution of natural gas in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland – through our seven natural gas distribution utilities. We are also involved in several other businesses that are complementary to the distribution of natural gas. We have four reportable segments that consist of the following – distribution operations, retail operations, wholesale services and midstream operations – and one non-reportable segment – other. These segments are consistent with how management views and operates our business. Amounts shown in this Item 7, unless otherwise indicated, exclude assets held for sale and discontinued operations. See Note 14 to our consolidated financial statements under Item 8 herein for additional information. The following table provides certain information on our segments.

	EBIT			Assets			Capital expenditures		
	2014 (1)	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Distribution operations	52%	84%	84%	81%	82%	82%	93%	93%	84%
Retail operations	12	20	18	5	5	4	1	1	1
Wholesale services	38	-	-	9	8	9	-	-	-
Midstream operations	(1)	(2)	2	5	5	5	2	2	8
Other/intercompany eliminations	(1)	(2)	(4)	-	-	-	4	4	7
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

(1) The EBIT in 2014 was impacted by significantly higher-than-normal commercial activity realized in wholesale services, which is not indicative of future performance.

In the third quarter of 2014, we adjusted the accounting treatment for our previously reported non-cash revenue recognition associated with our regulatory infrastructure programs in our distribution operations segment. The adjustments did not affect previously reported operating cash flows, nor are they expected to affect capital expenditure plans or dividend payments. We do not expect these adjustments to impact the levels of return from our infrastructure replacement programs, as all amounts will be recovered in accordance with allowed recovery mechanisms. The adjustments relate only to the timing of recognition and do not impact rates charged to customers. Additionally, we adjusted the amortization of intangible assets for customer relationships and trade names in our retail operations segment to reflect the amortization expense on a basis consistent with the pattern of undiscounted cash flows used to determine their fair values. In November 2014, we amended our 2013 Form 10-K and our Forms 10-Q for the quarters ended March 31, 2014 and June 30, 2014 to revise our financial statements to reflect these adjustments. Our prior-period financial statements included herein reflect these adjustments.

In September 2014, we closed on the sale of Tropical Shipping and received after-tax cash proceeds of approximately $225 million, as well as repatriated $86 million in cash. The transaction resulted in expenses, including taxes, of approximately $80 million or $(0.67) per share in 2014. Tropical Shipping operated as part of our cargo shipping segment and the financial results are classified as discontinued operations. Accordingly, all references to continuing operations exclude the operations of Tropical Shipping. The sale of Tropical Shipping allows us to focus on growing our core business of operating regulated utilities and complementary non-regulated energy businesses and provided us with flexibility around our near-term financing plans. For additional information on our discontinued operations, see Note 14 to our consolidated financial statements under Item 8 herein.

In 2014, our net income from continuing operations was $580 million, an increase of $272 million compared to income from continuing operations in 2013. This increase was primarily the result of significantly higher commercial activity and net hedge gains at wholesale services, mainly due to natural gas market volatility. This volatility was primarily generated by significantly colder-than normal weather in the first quarter of 2014, which also increased the operating margins at distribution operations and retail operations. Excluding the favorable weather impacts, we also achieved growth in our operating margins during 2014 as a result of targeted acquisition growth in retail operations. Our operating expenses in 2014 were higher compared to 2013 mainly as a result of higher incentive compensation expenses primarily related to higher earnings in 2014.

Our priorities for 2015 are consistent with the direction we have taken the company over the last several years. We will remain focused on efficient operations across all of our businesses, including offsetting inflationary pressures by aggressive cost controls, spreading costs across a broader customer base and sizing our operations to properly reflect market conditions. Several of our specific business objectives are detailed as follows:

- **Distribution Operations**: Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand the system and capitalize on potential customer conversions. We intend to continue investing in our regulatory infrastructure programs in Georgia, Virginia, New Jersey and Tennessee to minimize regulatory lag and the recovery cycle. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we will implement rates under the program effective in March 2015. We continue to effectively manage costs and leverage our shared services model across our businesses to largely overcome inflationary effects.

- **Retail Operations**: Maintain operating margins in Georgia and Illinois while continuing to expand into other profitable retail markets; expand our warranty businesses through partnership opportunities with our affiliates. We expect the Georgia retail market to remain highly competitive; however, our operating margins are forecasted to remain stable with modest growth and expansion into new markets.
- **Wholesale Services**: Maximize storage and transportation positions; effectively perform on existing asset management agreements, and expand customer base and maintain cost structure in line with market fundamentals. We anticipate volatility to remain low to moderate in certain areas of our portfolio; however, we expect near-term volatility in the supply-constrained Northeast corridor until expected new pipeline projects are completed and new capacity is placed into service. We continue to position our business to secure sufficient supplies of natural gas to meet the needs of our utility and third-party customers and to hedge natural gas prices to manage costs effectively, reduce price volatility and maintain a competitive advantage.
- **Midstream Operations**: Optimize storage portfolio, including contracts that have expired or will expire, pursue LNG transportation and natural gas pipeline opportunities and evaluate alternate uses for our storage facilities. In 2014, we announced our participation in three pipeline projects that we expect to provide a diverse source of natural gas to our customers in Georgia, New Jersey and Virginia. Subject to regulatory approvals, construction is expected to begin in the 2016-2017 timeframe with completion targeted in 2017-2018. For additional information on our pipeline projects, see Note 2 and Note 10 to our consolidated financial statements under Item 8 herein and Item 1, “Business” under the caption “Midstream Operations.”

Additionally, we will maintain our strong balance sheet and liquidity profile, solid investment grade ratings and our commitment to sustainable annual dividend growth. For additional information on our reportable segments, see Note 13 to our consolidated financial statements under Item 8 herein and Item 1, “Business.”

Results of Operations

We generate the majority of our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed to residential, commercial and industrial customers from the date of the last bill to the end of the reporting period. No individual customer or industry accounts for a significant portion of our revenues. The following table provides more information regarding the components of our operating revenues.

In millions	2014	2013	2012
Residential	$2,877	$2,422	$2,011
Commercial	861	696	656
Transportation	458	487	474
Industrial	242	180	262
Other (1)	947	424	159
Total operating revenues	$5,385	$4,209	$3,562

(1) Includes significantly higher-than-normal revenues at wholesale services in 2014, which are not indicative of future performance.

We evaluate segment performance using the measures of EBIT and operating margin. EBIT includes operating income and other income and expenses. Items that we do not include in EBIT are financing costs, including interest expense and income taxes, each of which we evaluate on a consolidated basis. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of goods sold and revenue tax expense in distribution operations. Operating margin excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets. These items are included in our calculation of operating income as reflected in our Consolidated Statements of Income.

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of goods sold and revenue tax expenses can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail operations, wholesale services and midstream operations segments since it is a direct measure of operating margin before overhead costs. You should not consider operating margin an alternative to, or a more meaningful indicator of, our operating performance than operating income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, operating margin may not be comparable to similarly titled measures of other companies.

We also believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses and the additional accrual for the Nicor Gas PBR issue, provides investors with an additional measure of our performance. Adjusted basic and diluted earnings per share should not be considered an alternative to, or a more meaningful indicator of, our operating performance than our GAAP basic and diluted earnings per share. The following table reconciles operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income and our GAAP basic and diluted earnings per common share to our non-GAAP basic and diluted earnings per share – as adjusted, together with other consolidated financial information for the last three years.

In millions, except per share amounts	**2014**	**2013**	**2012**
Operating revenues	$5,385	$4,209	$3,562
Cost of goods sold	(2,765)	(2,110)	(1,583)
Revenue tax expense (1)	(130)	(110)	(85)
Operating margin	2,490	1,989	1,894
Operating expenses	(1,527)	(1,471)	(1,369)
Revenue tax expense (1)	130	110	85
Gain on disposition of assets	2	11	-
Nicor merger expenses	-	-	(20)
Operating income	1,095	639	590
Other income	14	16	24
EBIT	1,109	655	614
Interest expense, net	(179)	(170)	(183)
Income before income taxes	930	485	431
Income tax expense	(350)	(177)	(157)
Income from continuing operations	580	308	274
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income	500	313	275
Less net income attributable to the noncontrolling interest	18	18	15
Net income attributable to AGL Resources Inc.	$482	$295	$260
Amounts attributable to AGL Resources Inc.			
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Per common share data			
Diluted earnings per common share from continuing operations	$4.71	$2.45	$2.20
Diluted (loss) earnings per common share from discontinued operations (2)	(0.67)	0.04	0.01
Additional accrual for Nicor Gas PBR issue	-	-	0.04
Transaction costs of Nicor merger	-	-	0.11
Diluted earnings per share - as adjusted	$4.04	$2.49	$2.36

(1) Adjusted for Nicor Gas' revenue tax expenses, as they are passed through directly to customers.

(2) In September 2014, we closed on the sale of Tropical Shipping. See Note 14 to our consolidated financial statements under Item 8 herein for additional information.

In 2014, our income from continuing operations attributable to AGL Resources Inc. increased by $272 million, or 94% compared to 2013. This increase was primarily the result of the following:

- Significantly higher commercial activity primarily in the first quarter of 2014, and mark-to-market hedge gains, net of LOCOM adjustments at wholesale services in 2014 from price volatility generated by colder-than-normal weather, which increased operating margin by $462 million compared to 2013.
- Increased operating margin at distribution operations and retail operations of $50 million mainly due to significantly colder-than-normal weather in 2014 compared to slightly colder-than-normal weather in 2013, as well as customer usage and customer growth. We also achieved growth as a result of our 2013 acquisitions and expansion into additional markets at retail operations.
- These increases were partially offset by a decrease in margin of $10 million at midstream operations primarily due to a retained fuel true-up at one of our storage facilities as a result of naturally occurring shrinkage of the caverns, as well as lower contracted firm rates at Jefferson Island and Central Valley.
- Favorability year-over-year was negatively impacted by higher incentive compensation expenses primarily related to higher earnings in 2014 and increased outside services expenses of $49 million, and the $8 million higher pre-tax gain in 2013 related to the sale of Compass Energy.
- Our income tax expense from continuing operations increased by $173 million for 2014 compared to 2013, primarily due to higher consolidated earnings. The increase was primarily a result of increased earnings at wholesale services.

In 2013, our income from continuing operations attributable to AGL Resources Inc. increased by $31 million, or 12% compared to 2012.

- The overall increase was primarily the result of increased operating margin at distribution operations and retail operations due to weather that was both colder-than-normal and colder than the prior year, increased regulatory infrastructure program revenues at Atlanta Gas Light, the acquisition of service contracts and residential and commercial energy customer relationships in our retail operations segment, as well as lower depreciation expense at Nicor Gas.
- The increase was unfavorably impacted by mark-to-market accounting hedge losses in our wholesale services segment during the second half of 2013, offset by higher commercial activity and the $11 million pre-tax gain on the sale of Compass Energy in 2013.

- Our midstream operations segment was unfavorable compared to 2012 due to the $8 million loss associated with the termination of the Sawgrass Storage project in 2013, as well as lower contracted firm rates at Jefferson Island and higher operating expenses at Golden Triangle, Central Valley and Pivotal LNG resulting from full year operations in 2013 as compared to partial year operations in 2012.
- Favorability year-over-year was also partially offset by higher incentive compensation expenses in most of our businesses, as our incentive compensation expense was above targeted levels in 2013 based on improved financial and operational performance compared to significantly below targeted annual levels in 2012 due to below target performance. In addition, our bad debt expense increased at distribution operations and retail operations primarily as a result of higher revenues from colder weather combined with natural gas prices that were higher than the prior year.
- In 2012, we recorded $20 million ($13 million net of tax) of Nicor merger-related expenses.
- In 2013, our interest expense decreased by $13 million compared to 2012. This decrease was the result of overall lower interest rates mostly offset by higher average debt outstanding primarily as a result of issuing $500 million of senior notes in place of variable-rate debt.
- In 2013, our income tax expense increased by $20 million or 13% compared to 2012 primarily due to higher consolidated earnings, as previously discussed.

The variances for each reportable segment are contained within the year-over-year discussion on the following pages.

Operating metrics

Weather We measure the effects of weather on our business primarily through Heating Degree Days, and we also consider operating costs that may vary with the effects of weather. Generally, increased Heating Degree Days result in higher demand for gas on our distribution systems. With the exception of Nicor Gas and Florida City Gas, we have various regulatory mechanisms, such as weather normalization mechanisms, which limit our exposure to weather changes within typical ranges in each of our utilities' respective service areas. However, our customers in Illinois and our retail operations customers in Georgia can be impacted by warmer or colder-than-normal weather. We have presented the Heating Degree Day information for those locations in the following table.

	Normal (1)	2014	2013	2012	2014 vs. 2013 colder (warmer)	2013 vs. 2012 colder (warmer)	2014 vs. normal colder (warmer)	2013 vs. normal colder (warmer)	2012 vs. normal colder (warmer)
Year ended December 31,									
Illinois (2)	5,752	6,556	6,305	4,863	4%	30%	14%	10%	(15)%
Georgia	2,599	2,882	2,689	1,934	7%	39%	11%	3%	(26)%
Quarter ended December 31,									
Illinois (2)	2,085	2,103	2,383	1,890	(12)%	26%	1%	14%	(9)%
Georgia	1,014	1,003	1,049	878	(4)%	19%	(1)%	3%	(13)%

(1) Normal represents the 10-year average from January 1, 2004 through December 31, 2013, for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, as obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(2) The 10-year average Heating Degree Days established by the Illinois Commission in our last rate case, is 2,020 for the fourth quarter and 5,600 for the 12 months from 1998 through 2007.

In 2014, we experienced weather in Illinois that was 14% colder-than-normal and 4% colder than 2013. This weather positively impacted our 2014 EBIT at our utilities, primarily at Nicor Gas, by $20 million, and drove an increase of $12 million in 2013 based on 10-year normal weather. Georgia also experienced 11% colder-than-normal weather, and 7% colder weather than the same period last year. Colder-than-normal weather increased EBIT at retail operations by $14 million in 2014 and $9 million in 2013 compared to expected levels based on 10-year normal weather.

Customers The number of customers at distribution operations and energy customers at retail operations can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Our energy customers at retail operations are primarily located in Georgia and Illinois. Our customer metrics highlight the average number of customers to which we provide services and are presented in the following table.

	Years ended December 31,			2014 vs. 2013 change		2013 vs. 2012 change	
(in thousands)	2014	2013	2012	#	%	#	%
Distribution operations customers (1)	4,497	4,479	4,459	18	0.4%	20	0.4%
Retail operations							
Energy customers (2)	628	619	623	9	1%	(4)	(1)%
Service contracts (3)	1,182	1,127	684	55	5%	443	65%
Market share in Georgia	31%	31%	32%		-%		(1)%

(1) In 2014, we implemented a process change at Nicor Gas that adversely impacted our customer count. This had the effect of immaterial growth for Nicor Gas from last year. Excluding Nicor Gas, our customer growth rate for 2014 was 0.8%.

(2) Increase from 2013 to 2014 primarily due to the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013.

(3) Increase from 2012 to 2013 primarily due to acquisition of approximately 500,000 contracts on January 31, 2013.

We anticipate overall utility customer growth trends for 2014 to continue in 2015 based on an expectation of continuing improvement in the economy and relatively low natural gas prices. We use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include adding residential customers, multifamily complexes and commercial and industrial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new natural gas related programs, products and services to enhance customer growth, mitigate customer attrition and increase operating revenues. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. We also target customer conversions to natural gas from other energy sources, emphasizing the pricing advantage of natural gas. These programs focus on premises that could be connected to our distribution system at little or no cost to the customer. In cases where conversion cost can be a disincentive, we may employ rebate programs and other assistance to address customer cost issues.

In 2015, we intend to continue efforts in our retail operations segment to enter into targeted markets and expand energy customers and its service contracts. We anticipate this expansion will provide growth opportunities in future years.

Volume Our natural gas volume metrics for distribution operations and retail operations present the effects of weather and customers' demand for natural gas compared to the prior year. Wholesale services' daily physical sales volumes represent the daily average natural gas volumes sold to its customers. Our volume metrics are presented in the following table:

	Year ended December 31,				
Distribution operations (In Bcf)	**2014**	**2013**	**2012**	**2014 vs. 2013 % change**	**2013 vs. 2012 % change**
Firm (1)	766	720	606	6%	19%
Interruptible	106	111	107	(5)%	4%
Total	872	831	713	5%	17%
Retail operations (In Bcf)					
Georgia firm	41	38	31	8%	23%
Illinois	17	9	8	89%	13%
Other (includes Florida, Maryland, New York and Ohio)	10	8	8	25%	-
Wholesale services					
Daily physical sales (Bcf/day)	6.32	5.73	5.54	10%	3%

(1) Year-over-year increases are primarily a result of colder weather.

Within our midstream operations segment, our natural gas storage businesses seek to have a significant portion of their working natural gas capacity under firm subscription, but also take into account current and expected market conditions. This allows our natural gas storage business to generate additional revenue during times of peak market demand for natural gas storage services, but retain some consistency with their earnings and maximize the value of the investments.

Our midstream operations storage business is cyclical, and the abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. Consistent with our expectations, we had contracts expire in 2014 that were re-subscribed at lower prices as compared to prior years. We anticipate these lower natural gas prices to continue in 2015 as compared to historical averages. We expect the rates at which we re-contract expiring capacity in 2015 to be marginally higher than re-contracting rates in 2014, but still significantly below historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy continues to improve, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. As of the periods presented, the overall monthly average firm subscription rates per facility and amount of firm capacity subscription were as follows:

	December 31, 2014		**December 31, 2013**	
	Avg. rates (1)	**Firm capacity under subscription** (1)	**Avg. rates** (1)	**Firm capacity under subscription** (1)
Jefferson Island	$0.108	4.6	$0.122	5.6
Golden Triangle	0.114	5.0	0.240	2.0
Central Valley	0.062	2.5	0.130	3.0

(1) Rates are per dekatherm. Firm capacity under subscription excludes 7 Bcf contracted by Sequent as of December 31, 2014, at an average monthly rate of $0.050 and 3.5 Bcf as of December 31, 2013, at an average monthly rate of $0.091.

Segment information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the last three years.

In millions	Operating Margin (1) (2)			Operating Expenses (2) (3)			EBIT (1)		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013** (4)	**2012**
Distribution operations	$1,648	$1,615	$1,552	$1,075	$1,083	$1,044	$581	$546	$517
Retail operations	311	294	247	179	162	136	132	132	111
Wholesale services	501	39	50	79	53	54	422	(3)	(3)
Midstream operations	31	41	46	50	46	38	(17)	(10)	10
Other (5)	7	8	7	22	25	40	(9)	(10)	(21)
Intercompany eliminations	(8)	(8)	(8)	(8)	(8)	(8)	-	-	-
Consolidated	$2,490	$1,989	$1,894	$1,397	$1,361	$1,304	$1,109	$655	$614

(1) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income, and EBIT to earnings before income taxes and net income is contained in "Results of Operations" herein. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information.
(2) Operating margin and operating expenses are adjusted for revenue tax expenses, which are passed through directly to our customers.
(3) Includes $20 million in Nicor merger transaction expenses for 2012 and an $8 million accrual in 2012 for the Nicor Gas PBR issue.
(4) EBIT for 2013 includes an $11 million pre-tax gain on sale of Compass Energy in our wholesale services segment and an $8 million pre-tax loss associated with the termination of the Sawgrass Storage project within our midstream operations segment.
(5) Our "other" non-reportable segment includes our investment in Triton, which was formerly part of our cargo shipping segment that is now classified as discontinued operations. See Note 14 to our consolidated financial statements under Item 8 herein for additional information.

During the Heating Season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale services operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain Consolidated Statements of Financial Position items across quarters, including receivables, unbilled revenue, inventories and short-term debt. However, these items are comparable when reviewing our annual results. Our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality. The EBIT of our distribution operations, retail operations and wholesale services segments are seasonal, as indicated in the table below.

% generated during Heating Season

	Revenues	EBIT
2014	73%	81%
2013	68	72
2012	70	76

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our second largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. We have various mechanisms, such as weather normalization mechanisms at our utilities and weather derivative instruments that limit our exposure to weather changes within typical ranges in their respective service areas.

In millions	2014	2013
EBIT - prior year	**$546**	**$517**
Operating margin		
Increase mainly driven by non-weather-related customer usage and customer growth	22	9
Increased margin as a result of higher customer usage due to colder-than-normal weather	13	36
Increase from regulatory infrastructure programs, primarily at Atlanta Gas Light	10	4
(Decrease) increase primarily as a result of bad debt and energy efficiency program recoveries at Nicor Gas	(12)	19
Decreased gas storage carrying amounts at Atlanta Gas Light	-	(5)
Increase in operating margin	**33**	**63**
Operating expenses		
Decreased depreciation expense primarily due to the impact of Nicor Gas' new composite depreciation rate effective August 30, 2013, partially offset by increased PP&E from infrastructure additions and improvements	(22)	(8)
Decreased benefit expenses primarily related to lower pension costs due to change in actuarial gains and losses	(13)	(6)
(Decreased) increased rider expenses primarily as a result of energy efficiency program expenses at Nicor Gas	(12)	19
Increased payroll and variable compensation costs as a result of merit increases and higher earnings	19	37
Increased outside services and other expenses mainly as a result of maintenance programs	11	1
Increase due to weather-related expenses	5	-
Increased bad debt expenses related to colder-than-normal weather primarily at Elizabethtown Gas	4	4
Decreased operation and maintenance expense at Nicor Gas related to the 2012 PBR accrual	-	(8)
(Decrease) increase in operating expenses	**(8)**	**39**
(Decrease) increase in other income primarily from STRIDE Projects at Atlanta Gas Light	**(6)**	**5**
EBIT - current year	**$581**	**$546**

Retail Operations

Our retail operations segment, which consists of several businesses that provide energy-related products and services to retail markets, is also weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. During 2014, our retail operations' EBIT was negatively impacted by $16 million of unrealized hedge losses and LOCOM adjustments.

In millions	2014	2013
EBIT - prior year	**$132**	**$111**
Operating margin		
Increase due to acquisitions in January and June 2013	9	35
Increase primarily related to customer usage in Georgia and Illinois due to colder-than-normal weather, net of weather hedges	8	18
Increase primarily related to warranty service contract count and price increases	6	-
Increase primarily related to non-weather related customer usage and customer growth	5	1
Increase (decrease) related to change in gas costs and from retail price spreads	5	(11)
Change in value of derivatives as a result of changes in NYMEX natural gas prices	(13)	1
Change in LOCOM adjustment, net of recoveries	(3)	3
Increase in operating margin	**17**	**47**
Operating expenses		
Increased variable compensation costs, outside services, marketing and other	11	-
Increased due to weather-related expenses	3	-
Increased bad debt expenses primarily related to higher natural gas prices	2	3
Increased expenses primarily due to acquisitions in January and June 2013	1	23
Increase in operating expenses	**17**	**26**
EBIT - current year	**$132**	**$132**

Wholesale Services

Our wholesale services segment is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services and wholesale marketing. We have positioned the business to generate positive economic earnings even under low volatility market conditions. However, when market price volatility increases as we experienced in 2014, we are well positioned to capture significant value and generate stronger results. Results in 2014 for the wholesale services segment were the best in the company's history and not indicative of future performance. EBIT for our wholesale services segment is impacted by volatility in the natural gas market arising from a number of factors, including weather fluctuations and changes in supply or demand for natural gas in different regions of the country. We principally use physical and financial arrangements to reduce the risks associated with fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, our reported earnings for wholesale services reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues.

In millions	2014	2013
EBIT - prior year	**$(3)**	**$(3)**
Operating margin		
Change in commercial activity largely driven by the transportation and storage portfolios in the Northeast and Midwest	319	90
Change in value of transportation and forward commodity derivatives from price movements related to natural gas transportation positions	111	(70)
Change in value of storage derivatives as a result of changes in NYMEX natural gas prices	102	(30)
Change in LOCOM adjustment, net of estimated current period recoveries	(66)	3
Decrease due to sale of Compass Energy in May 2013	(4)	(4)
Increase (decrease) in operating margin	**462**	**(11)**
Operating expenses		
Increased variable compensation expenses related to higher earnings and slightly higher other costs in 2014	28	3
Decrease due to sale of Compass Energy in May 2013	(2)	(4)
Increase (decrease) in operating expenses	**26**	**(1)**
(Decrease) increase in other income, primarily related to the gain on sale of Compass Energy	(11)	10
EBIT - current year	**$422**	**$(3)**

The following table illustrates the components of wholesale services' operating margin for the periods presented.

In millions	2014	2013	2012
Commercial activity recognized	$444	$129	$43
Gain (loss) on transportation and forward commodity derivatives	38	(73)	(3)
Gain (loss) on storage derivatives	86	(16)	14
Inventory LOCOM adjustment, net of estimated current period recoveries	(67)	(1)	(4)
Operating margin	$501	$39	$50

Change in commercial activity The commercial activity at wholesale services includes recognized storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur in the period. Additionally, the commercial activity includes operating margin generated and recognized in the current period. For 2014, commercial activity increased significantly due to:

- the recognition of significantly higher operating margin associated with our transportation and storage portfolios, particularly in the Northeast and Midwest regions, from price volatility generated by significantly colder-than-normal weather in 2014, in part reflecting Sequent's strategy and focus on providing asset management and related services to producers around the major shale-producing regions and to natural gas-fired power generators, enabling Sequent to optimize the associated pipeline transportation and storage capacity assets
- the recognition of operating margin resulting from the withdrawal of storage inventory hedged at the end of 2013 that was included in the storage withdrawal schedule with a value of $28 million as of December 31, 2013
- the recognition of operating margin resulting from mark-to-market accounting derivative losses at the end of 2013

The 2013 change in commercial activity was primarily due to increased cash optimization opportunities related to constraints of natural gas purchased from producers in the Northeastern U.S. Commercial activity in 2013 was also impacted by the recognition of operating margin resulting from the withdrawal of storage inventory hedged at the end of 2012 that was included in the storage withdrawal schedule with a value of $27 million as of December 31, 2012. Additionally, increased volatility associated with colder weather contributed to the increase in commercial activity.

Change in storage and transportation derivatives A return of significantly higher price volatility in 2014 benefitted Sequent's portfolio of pipeline transportation and storage capacity assets throughout the country, primarily in the Gulf Coast, Northeast and Midwest markets. Storage derivative gains in 2014 are primarily due to the change in natural gas prices applicable to the locations of our specific storage assets. These increases were partially offset by a $66 million increase in the required LOCOM adjustment to natural gas inventories for the year ended December 31, 2014, net of estimated hedging recoveries.

Gains in our transportation and forward commodity derivative positions in 2014 are primarily the result of narrowing transportation basis spreads. Significantly colder-than-normal weather and higher demand together with natural gas transportation constraints due to growing shale production impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast and the Midwest regions, during 2014. Transportation and forward commodity hedge losses in 2013 were the result of widening transportation basis spreads, and were recovered in 2014 with the physical flow of natural gas and utilization of the contracted transportation capacity.

We account for natural gas stored in inventory differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The natural gas that we purchase and inject into storage is accounted for at the LOCOM value utilizing gas daily or spot prices at the end of the year. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period using forward natural gas prices. This difference in accounting treatment can result in volatility in wholesale services reported results, even though the expected net operating revenue and expected economic value are substantially unchanged since the date the transactions were initiated. These accounting timing differences also affect the comparability of wholesale services' period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year. Largely as a result of moderate weather in the fourth quarter of 2014 leading to significant decreases in natural gas prices, wholesale services recorded a $73 million LOCOM adjustment for the year ended December 31, 2014.

For our natural gas transportation portfolio, we enter into transportation capacity contracts with interstate and intrastate pipelines for the delivery of natural gas between receipt and delivery points in future periods. We purchase natural gas for transportation when the market price we pay for gas at a receipt point plus the cost of transportation capacity required to deliver the gas to the delivery point is less than the sales price at the delivery point. The difference between the prices at the receipt point and the delivery point is the transportation basis or location spread. Similar to our storage transactions, we attempt to mitigate the commodity price risk associated with our transportation portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas at the receipt and delivery points. We utilize futures contracts or OTC derivatives to hedge both the commodity price risk relative to the market price at the receipt point and the market price at the delivery point to substantially protect the operating revenue that we will ultimately realize once the natural gas is received, delivered and sold.

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. During both 2014 and 2013, we experienced increased price volatility brought on largely by colder weather and supply constraints in the Northeast and Midwest regions, which enabled us to capture value under these market conditions. Commercial activity in 2014 was particularly favorable due to significant natural gas price volatility as compared to prior years, largely the result of significantly colder-than-normal weather primarily in the first quarter. Prior year volatility was significantly lower due to lower daily Henry Hub spot market prices for natural gas in the U.S., robust natural gas supply, mild weather and ample storage.

While market conditions in 2014 experienced more natural gas price volatility, in the near term we anticipate low volatility in certain areas of our portfolio, but expect a continuation of some volatility in the supply-constrained Northeast corridor. Over the longer term, we expect volatility to be low to moderate and locational or transportation spreads to decrease over time as new pipelines are built to reduce the bottleneck in the currently constrained shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, our expectations are that volatility would increase. While natural gas supply increased during the 2013/2014 Heating Season in the U.S., it was not enough to meet the increased demand, resulting in the lowest storage levels in over a decade. U.S. storage levels have been restored but not to the level of previous years, which could lead to higher natural gas prices under colder-than-normal weather conditions. Additional economic factors may contribute to this environment, including the significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers and reduced levels of natural gas production. Further, if economic conditions continue to improve, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer-term basis. We continue to position Sequent's business model with respect to fixed costs and the types of contracts pursued and executed, focusing on opportunities associated with expected new builds of power generation stations, LNG exporters and natural gas utilities and producers.

Sequent's expected natural gas withdrawals from storage and expected offset to hedge losses/gains associated with Sequent's transportation portfolio at December 31, 2014 are presented in the following tables, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Sequent's expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt and delivery charges, but are net of the estimated impact of profit sharing under our asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points and forward natural gas prices at December 31, 2014. A portion of Sequent's storage inventory and transportation capacity is economically hedged with futures contracts, which results in realization of substantially fixed net operating revenues, timing notwithstanding.

	Storage withdrawal schedule		
Dollars in millions	**Total storage** (in Bcf) (WACOG $2.92)	**Expected net operating (losses) gains** (1)	**Physical transportation transactions – expected net operating losses** (2)
2015	66	$(5)	$(19)
2016 and thereafter	5	2	(19)
Total at December 31, 2014 (3)	71	$(3)	$(38)

(1) Represents expected operating gains (losses) from planned storage withdrawals associated with existing inventory positions and could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations.

(2) Represents the periods associated with the transportation derivative (gains) losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative (gains) losses recognized.

(3) Includes 5 Bcf in storage with expected operating revenues of $2 million that is currently inaccessible due to operational issues at a third-party storage facility. The owner of this facility is working to resolve these issues and the facility is expected to be operational by mid-2015. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

For the year ended December 31, 2014, we have recorded $86 million in gains associated with the hedging of our storage position, compared to $16 million in storage hedge losses in 2013. These hedge gains primarily relate to changes in natural gas prices during the fourth quarter of 2014 largely resulting from moderate weather. Sequent's storage withdrawals associated with existing inventory positions could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate.

The net operating (losses) revenues expected to be generated from the physical withdrawal of natural gas from storage do not reflect the earnings impact related to the movement in our hedges to lock in the forward location spread for the delivery of natural gas between two transportation delivery points associated with our transportation capacity portfolio.

For the year ended December 31, 2014, we have recorded $38 million in gains associated with the hedging of our transportation portfolio as compared to hedge losses of $73 million for the same period last year. Hedge losses in 2013 primarily related to forward transportation and commodity positions for 2014 and were largely offset in 2014 when the expected economic value was realized upon the physical flow of natural gas and the utilization of the contracted transportation capacity.

For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Natural Gas Price Risk."

For a discussion of commercial activity, see Item 1, "Business" under the caption "Wholesale Services."

Midstream Operations

Our midstream operations segment's primary activity is operating non-utility storage and pipeline facilities, including the development and operation of high-deliverability underground natural gas storage and pipeline assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, certain of our storage services are covered under short-, medium- and long-term contracts at fixed market rates. Based on an engineering study and mechanical integrity tests performed in 2014, we identified a lower amount of working gas capacity, further resulting in the true-up of retained fuel at one of our storage facilities, negatively impacting EBIT by $10 million for the year ended December 31, 2014. The decrease in working gas capacity is a result of naturally occurring shrinkage of the storage cavern, and we are developing strategies to recover the decreased working capacity.

In millions	**2014**	**2013**
EBIT - prior year	**$(10)**	**$10**
Operating margin		
Decrease at Jefferson Island and Central Valley primarily due to lower subscription rates, as well as hedge gains at Central Valley in 2012 that did not occur in 2013	(6)	(5)
Decrease at one of our storage facilities related to true-up of retained fuel, partially offset by higher interruptible operating margins largely at Golden Triangle in 2014 due to optimizing the facilities during the significantly colder weather in 2014	(4)	-
Decrease in operating margin	**(10)**	**(5)**
Operating expenses		
Increased maintenance, outside service costs, depreciation expense and other	4	-
Increase from Central Valley Storage and Cavern 2 at Golden Triangle both beginning commercial service during 2012, and entry into the LNG markets	-	8
Increase in operating expenses	**4**	**8**
Increase (decrease) in other income, primarily related to the impairment loss at Sawgrass Storage in December 2013	**7**	**(7)**
EBIT - current year	**$(17)**	**$(10)**

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs primarily related to our natural gas inventory are our most significant short-term financing requirements. The liquidity required to fund these short-term needs is primarily provided by our operating activities, and any needs not met are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas Credit Facility. For more information on the seasonality of our short-term borrowings, see "Short-term Debt" later in this section. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner.

Our financing activities, including long-term and short-term debt and equity, are subject to customary approval or review by state and federal regulatory bodies, including the various commissions of the states in which we conduct business. Certain financing activities we undertake may also be subject to approval by state regulatory agencies. A substantial portion of our consolidated assets, earnings and cash flows is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. Nicor Gas is restricted by regulation in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates.

We believe the amounts available to us under our long-term debt and credit facilities, as well as through the issuance of debt and equity securities combined with cash provided by operating activities will continue to allow us to meet our needs for working capital, pension and retiree welfare benefits, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years. However, considering our January 2015 maturity of $200 million of senior notes that were repaid with commercial paper, our higher expected capital expenditures related to utility rate base and infrastructure investment and our recently announced pipeline projects, we anticipate issuing additional long-term debt as our financing needs and market conditions warrant.

Our ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors include, among others, regulatory changes, the price of and demand for natural gas, and operational risks.

Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of debt and equity securities. This strategy includes active management of the percentage of total debt relative to total capitalization, as well as the term and interest rate profile of our debt securities and maintenance of an appropriate mix of debt with fixed and floating interest rates. Our variable debt target is 20% to 45% of total debt. As of December 31, 2014, our variable-rate debt was $1.5 billion, or 31%, of our total debt, compared to $1.4 billion, or 28%, as of December 31, 2013. The increase was due to $120 million of senior notes that converted from fixed-rate to variable-rate during 2014. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

In January 2015, we executed $800 million in notional value of 10 year and 30 year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated issuances of senior notes in 2015 and 2016. These debt issuances will be used to reduce our commercial paper for the amount that was borrowed to repay our senior notes that matured in January 2015 and to fund upcoming debt maturities as well as the capital expenditures associated with increased utility investment and construction of our new pipeline projects. We have designated the forward-starting interest rate swaps, which will mature on the debt issuance dates, as cash flow hedges. See Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Interest Rate Risk” for additional information.

Our objective continues to be maintaining our strong balance sheet and liquidity profile, solid investment grade ratings and our annual dividend growth. Additionally, we will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies, acquisitions and other factors. See Item 1A, “Risk Factors” for additional information on items that could impact our liquidity and capital resource requirements.

Short-term Debt The following table provides additional information on our short-term debt throughout the year.

In millions	**Year-end balance outstanding** (1)	**Daily average balance outstanding** (2)	**Minimum balance outstanding** (2)	**Largest balance outstanding** (2)
Commercial paper - AGL Capital	$590	$399	$-	$1,006
Commercial paper - Nicor Gas	585	279	58	614
Senior notes (3)	200	192	-	200
Total short-term debt and current portion of long-term debt	$1,375	$870	$58	$1,820

(1) As of December 31, 2014.
(2) For the twelve months ended December 31, 2014. The minimum and largest balances outstanding for each debt instrument occurred at different times during the year. Consequently, the total balances are not indicative of actual borrowings on any one day during the year.
(3) These senior notes matured in January 2015 and were repaid using commercial paper.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuations of our short-term borrowings and potential liquidity risk. The fluctuations are due to our seasonal cash requirements to fund working capital needs, in particular the purchase of natural gas inventory, margin calls and collateral posting requirements. Cash requirements generally increase between June and December as we purchase natural gas in advance of the Heating Season. The timing differences of when we pay our suppliers for natural gas purchases and when we recover our costs from our customers through their monthly bills can significantly affect our cash requirements. Our short-term debt balances are typically reduced during the Heating Season, as a significant portion of our current assets, primarily natural gas inventories, are converted into cash.

Our commercial paper borrowings are supported by the $1.3 billion AGL Credit Facility and $700 million Nicor Gas Credit Facility. The credit facilities can be drawn upon to meet working capital and other general corporate needs; however, the Nicor Gas Credit Facility can only be used for the working capital needs of Nicor Gas. The interest rates payable on borrowings under these facilities are calculated either at the alternative base rate, plus an applicable margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to AGL Capital’s and Nicor Gas’ current credit ratings. At December 31, 2014 and 2013, we had no outstanding borrowings under either credit facility.

The timing of natural gas withdrawals is dependent on the weather and natural gas market conditions, both of which impact the price of natural gas. Increasing natural gas commodity prices can significantly impact our commercial paper borrowings. Based upon our total debt outstanding as of December 31, 2014, and our maximum 70% debt to total capitalization allowed under our financial covenants, we could potentially borrow an additional $700 million of commercial paper under the AGL Credit Facility and an additional $100 million of commercial paper under the Nicor Gas Credit Facility. As a result, based on current natural gas prices and our expected injection plan, we believe that we have sufficient liquidity to cover our working capital needs.

The lenders under our credit facilities and lines of credit are major financial institutions with $2.2 billion of committed balances and all had investment grade credit ratings as of December 31, 2014. It is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal. Commercial paper borrowings reduce availability of these credit facilities.

Long-term Debt Our long-term debt matures more than one year from December 31, 2014 and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1989; senior notes; first mortgage bonds and gas facility revenue bonds.

Our long-term cash requirements primarily depend upon the level of capital expenditures, long-term debt maturities and decisions to refinance long-term debt. The following table summarizes our long-term debt issuances over the last three years.

	Issuance date	**Amount** *(in millions)*	**Term** *(in years)*	**Interest rate**
Gas facility revenue bonds	(1)	$200	10-20	Floating rate
Senior notes (2)	May 2013	$500	30	4.4%

(1) During the first quarter of 2013, we refinanced the gas facility revenue bonds. We had no cash receipts or payments in connection with the refinancing.
(2) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $225 million we borrowed to repay senior notes that matured on April 15, 2013.

Credit Ratings Our borrowing costs and our ability to obtain adequate and cost-effective financing are directly impacted by our credit ratings, as well as the availability of financial markets. Credit ratings are important to our counterparties when we engage in certain transactions, including OTC derivatives. It is our long-term objective to maintain or improve our credit ratings in order to manage our existing financing costs and enhance our ability to raise additional capital on favorable terms.

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. The rating agencies regularly review our performance and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. A credit rating is not a recommendation to buy, sell or hold securities and each rating should be evaluated independently of other ratings.

Factors we consider important to assessing our credit ratings include our Consolidated Statements of Financial Position, leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. As of December 31, 2014, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $38 million to continue conducting business with certain customers. The following table summarizes our credit ratings as of December 31, 2014 and reflects no change from what was reported in our 2013 Form 10-K/A.

	AGL Resources			**Nicor Gas**		
	S&P	Moody's (1)	Fitch	S&P	Moody's	Fitch
Corporate rating	BBB+	n/a	BBB+	BBB+	n/a	A
Commercial paper	A-2	P-2	F2	A-2	P-1	F1
Senior unsecured	BBB+	A3	BBB+	BBB+	A2	A+
Senior secured	n/a	n/a	n/a	A	Aa3	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

(1) Credit ratings are for AGL Capital, whose obligations are fully and unconditionally guaranteed by AGL Resources.

A downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could limit our access to the commercial paper market. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

Default Provisions As indicated below, our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment or similar actions.

- Our credit facilities contain customary events of default, including but not limited to, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness and a change of control.

- Our credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations, and other matters customarily restricted in such agreements.
- Our credit facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. However, we typically seek to maintain these ratios at levels between 50% and 60%, except for temporary increases related to the timing of acquisition and financing activities. The following table contains our debt-to-capitalization ratios for December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2014	**2013**	**2014**	**2013**
Debt-to-capitalization ratio as calculated from our Consolidated Statements of Financial Position	57%	58%	62%	54%
Adjustments (1)	(2)	(1)	-	1
Debt-to-capitalization ratio as calculated within our credit facilities	55%	57%	62%	55%

(1) As defined in credit facilities, includes standby letters of credit, performance/surety bonds and excludes accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges.

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2014 and 2013. For more information on our default provisions, see Note 8 to our consolidated financial statements under Item 8 herein.

Cash Flows

We prepare our Consolidated Statements of Cash Flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in derivative instrument assets and liabilities, deferred income taxes, gains or losses on the sale of assets and changes in the Consolidated Statements of Financial Position for working capital from the beginning to the end of the period. The following table provides a summary of our operating, investing and financing cash flows for the last three years.

In millions	**2014**	**2013**	**2012**
Net cash provided by (used in) (1):			
Operating activities	$655	$971	$1,003
Investing activities	(505)	(876)	(786)
Financing activities	(224)	(121)	(155)
Net (decrease) increase in cash and cash equivalents - continuing operations	(51)	(26)	53
Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	-	9
Cash and cash equivalents (including held for sale) at beginning of period	105	131	69
Cash and cash equivalents (including held for sale) at end of period	31	105	131
Less cash and cash equivalents held for sale at end of period	-	24	23
Cash and cash equivalents (excluding held for sale) at end of period	$31	$81	$108

(1) Includes activity for discontinued operations.

Cash Flow from Operating Activities *2014 compared to 2013* Our net cash flow provided by operating activities in 2014 was $655 million, a decrease of $316 million or 33% from 2013. The decrease was primarily related to (i) income taxes, largely driven by the utilization of a prior period net operating loss that reduced the 2013 tax obligation combined with taxes paid in 2014 due to increased earnings and the repatriation of cumulative foreign earnings of Tropical Shipping, (ii) increased cash for inventory and (iii) trade payables, other than energy marketing, due to higher accrued volumes in December 2013 compared to December 2012. These decreases were partially offset by increases primarily related to (i) higher earnings year over year largely attributed to significantly colder-than-normal weather in the current year and increased price volatility that enabled us to capture value in wholesale services and (ii) net energy marketing receivables and payables, due to higher cash received in 2014 from the prior year.

2013 compared to 2012 Our net cash flow provided by operating activities in 2013 was $971 million, a decrease of $32 million or 3% from 2012. The decrease was primarily related to (i) receivables, other than energy marketing, due to colder weather in 2013, which resulted in higher volumes primarily at distribution operations and retail operations that will be collected in future periods and (ii) income taxes, from accelerated tax depreciation in 2013 than in 2012. This decrease in cash provided by operating activities was partially offset by increased cash provided by (i) lower payments for incentive compensation in 2013 as a result of reduced earnings in 2012 as compared to 2011 and (ii) trade payables, other than energy marketing, due to higher gas purchase volumes primarily at distribution operations and retail operations resulting from colder weather in 2013.

Cash Flow from Investing Activities Our net cash flow used in investing activities in 2014 decreased $371 million or 42% from 2013, primarily as a result of approximately $225 million proceeds we received from the sale of Tropical Shipping during the third quarter of 2014. The decrease was also attributed to the $122 million spending on the acquisition of approximately 500,000 service plans during the first quarter of 2013. Partially offsetting this decrease was greater spending for PP&E expenditures. Our estimated PP&E expenditures for 2015 and our actual PP&E expenditures incurred in 2014, 2013 and 2012 are quantified in the following table.

In millions	Description	2015 (1)	2014	2013	2012
Distribution business	New construction and infrastructure improvements	$408	$475	$421	$371
Regulatory infrastructure programs (2)	Programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth	424	180	226	263
Storage, pipelines and LNG facilities	Underground natural gas storage facilities, pipeline infrastructure and LNG production and transportation	103	15	8	61
Other	Primarily includes information technology and building and leasehold improvements	130	99	76	80
Total		$1,065	$769	$731	$775

(1) Estimated PP&E expenditures.
(2) Includes Investing in Illinois at Nicor Gas, STRIDE at Atlanta Gas Light, SAVE at Virginia Natural Gas and an enhanced infrastructure program at Elizabethtown Gas.

The 2014 increase in PP&E expenditures of $38 million, or 5%, was due to increased spending of $84 million primarily related to new construction and infrastructure improvements at our utilities. This was partially offset by a $46 million net decrease in expenditures for our regulatory infrastructure programs largely due to PRP at Atlanta Gas Light, which ended in 2013, offset by increased spending on our other regulatory infrastructure programs that primarily included $57 million at Atlanta Gas Light for i-VPR, $24 million at Elizabethtown Gas for AIR and $22 million at Nicor Gas for Investing in Illinois.

Our PP&E expenditures were $731 million for the year ended December 31, 2013, compared to $775 million for the same period in 2012.The decrease of $44 million, or 6%, was primarily due to decreased spending of $49 million on our natural gas storage projects consisting of $35 million at Central Valley and $14 million at Golden Triangle. Additionally, capital expenditures decreased $35 million for strategic projects and $16 million for utility infrastructure enhancement projects at Elizabethtown Gas. These decreases were partially offset by increased expenditures of $54 million for regulatory infrastructure programs at Atlanta Gas Light and $9 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our estimated expenditures for 2015 include discretionary spending for capital projects principally within the distribution business, regulatory infrastructure programs, natural gas storage and other categories. We continuously evaluate whether or not to proceed with these projects, reviewing them in relation to various factors, including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities Our net cash flow used in financing activities in 2014 increased $103 million, or 85% from 2013 primarily as the result of our $494 million issuance of senior notes in May 2013 and recovery of working capital at wholesale services, partially offset by our $225 million repayment of senior notes in April 2013 and lower commercial paper repayments in 2014 due to higher working capital needs at distribution operations. For more information on our financing activities, see short and long-term debt within Item 7 under the caption “Liquidity and Capital Resources.”

Noncontrolling Interest We recorded cash distributions for SouthStar’s dividend distributions to Piedmont of $17 million in 2014 and 2013, and $14 million in 2012 as financing activities in our Consolidated Statements of Cash Flows. The primary reason for the increase in the distribution to Piedmont from 2012 to 2013 was increased earnings for 2012 compared to 2011 and a distribution of excess working capital from the joint venture in 2013. Additionally, we received $22.5 million from Piedmont in 2013 to maintain their 15% ownership interest after we contributed our Illinois Energy business to the SouthStar joint venture.

Dividends on Common Stock Our common stock dividend payments were $233 million in 2014, $222 million in 2013 and $203 million in 2012. The increases were generally the result of the annual dividend increase of $0.04 per share for each of the last three years. However, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011 received a pro rata dividend of $0.0989 per share for the stub period, which accrued from November 19, 2011 and totaled $7 million. The dividend payments made in February 2012 were reduced by this stub period dividend. For information about restrictions on our ability to pay dividends on our common stock, see Note 9 to our consolidated financial statements under Item 8 herein.

Shelf Registration In July 2013, we filed a shelf registration statement with the SEC, which expires in 2016. Under this shelf registration statement, debt securities will be issued by AGL Capital and related guarantees will be issued by AGL Resources under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Mellon Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series, subject to our AGL Credit Facility financial covenant related to total debt to total capitalization.

Off-balance sheet arrangements We have certain guarantees, as further described in Note 11 to our consolidated financial statements under Item 8 herein. We believe the likelihood of any such payment under these guarantees is remote. No liability has been recorded for these guarantees. We also have authorized unrecognized ratemaking amounts, primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs, which are not reflected within our Consolidated Statements of Financial Position. See Note 3 to our consolidated financial statements under Item 8 herein for additional information.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of business that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services. The following table illustrates our expected future contractual obligation payments and commitments and contingencies as of December 31, 2014.

In millions	Total	2015	2016	2017	2018	2019	2020 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$200	$545	$22	$155	$350	$2,434
Short-term debt	1,175	1,175	-	-	-	-	-
Environmental remediation liabilities (2)	414	87	93	55	47	37	95
Total	$5,295	$1,462	$638	$77	$202	$387	$2,529
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$4,303	$805	$457	$280	$234	$222	$2,305
Interest charges (5)	2,762	179	171	147	146	141	1,978
Operating leases (6)	188	33	31	24	17	18	65
Asset management agreements (7)	32	9	10	7	4	2	-
Standby letters of credit, performance/surety bonds (8)	50	49	1	-	-	-	-
Other	8	3	3	1	1	-	-
Total	$7,343	$1,078	$673	$459	$402	$383	$4,348

(1) Excludes the $75 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $5 million interest rate swaps fair value adjustment. Includes the current portion of long-term debt of $200 million, which matured in January 2015.
(2) Includes charges recoverable through base rates or rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.
(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 51 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2014, and is valued at $142 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2014 and the maturity date of the underlying debt instrument. As of December 31, 2014, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2015.
(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Standby letters of credit and performance/surety bonds. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and the maximum potential amount of future payments that could be required of us as the guarantor. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and welfare obligations. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Pension Protection Act. We calculate any required pension contributions using the traditional unit credit cost method; however, additional voluntary contributions are periodically made. Contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. The contributions represent the portion of the welfare costs for which we are responsible under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions in all of our jurisdictions, except Illinois, have phase-ins that defer a portion of the retirement benefit expenses for retirement plans other than pensions for future recovery. We recorded a regulatory asset for these future recoveries of $122 million as of December 31, 2014 and $108 million as of December 31, 2013. In Illinois, all accrued retirement plan expenses are recovered through base rates. See Note 6 to our consolidated financial statements under Item 8 herein for additional information about our pension and welfare plans.

In both 2014 and 2013, no contributions were required to our qualified pension plans. Based on the estimated funded status of the AGL Pension plan, we do not expect any required contribution to the plan in 2015. We may, at times, elect to contribute additional amounts to the AGL Pension Plan in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Policies and Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts in our consolidated financial statements and accompanying notes. Those judgments and estimates have a significant effect on our financial statements, primarily due to the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently reevaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances. The following is a summary of our most critical accounting policies, which represent those that may involve a higher degree of uncertainty, judgment and complexity. Our significant accounting policies are described in Note 2 to our consolidated financial statements under Item 8 herein.

Accounting for Rate-Regulated Subsidiaries

At December 31, 2014, our regulatory assets were $714 million and regulatory liabilities were $1.7 billion. At December 31, 2013, our regulatory assets were $819 million and regulatory liabilities were $1.7 billion.

Our natural gas distribution operations and certain regulated transmission and storage operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the U.S. Accordingly, the financial results of these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject.

As a result, certain costs that would normally be expensed under GAAP are permitted to be capitalized or deferred on the balance sheet because it is probable that they can be recovered through rates. The periods in which revenues or expenses are recognized are impacted by regulation. In instances where other GAAP accounting treatment supersedes Accounting Standards Codification 980 - *Regulated Operations*, we apply the other GAAP accounting treatment. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations.

Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Assets and liabilities recognized as a result of rate regulation would be written off in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2014 would result in 5% and 15% decreases in total assets and total liabilities, respectively. For more information on our regulated assets and liabilities, see Note 2 and Note 3 to our consolidated financial statements under Item 8 herein.

Accounting for Goodwill and Long-Lived Assets, including Intangible Assets

Goodwill We do not amortize our goodwill, but test it for impairment at the reporting unit level during the fourth fiscal quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its carrying value, including goodwill. If the fair value is less than the carrying value, an impairment is indicated, and we must perform a second test to quantify the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value of the entire reporting unit determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we record an impairment charge. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective.

Under the income approach, fair value is determined based upon the present value of estimated future cash flows discounted at an appropriate risk-free rate that takes into consideration the time value of money, inflation and the risks inherent in ownership of the business being valued. These forecasts contain a degree of uncertainty, and changes in these projected cash flows could significantly increase or decrease the estimated fair value of the reporting unit. For the regulated reporting units, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach included return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and a discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

Under the market approach, fair value is determined by applying market multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

The goodwill impairment testing develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions that are subjective in nature and inherent to a discounted cash flows calculation. We weight the results of the two valuation approaches to estimate the fair value of each reporting unit.

The significant assumptions that drive the estimated fair values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC), oil prices and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment, as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2014 indicated that the estimated fair value of all but one of our reporting units with goodwill was in excess of the carrying value by approximately 30% to over 600%, and were not at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of the storage and fuels reporting unit with $14 million of goodwill exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2023 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year of which we estimated the terminal value. In the terminal year, we assumed a long-term earnings growth rate of 2.5%, which is consistent with our 2013 annual goodwill impairment test, and we believe is appropriate given the current economic and industry-specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2013 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next nine years. Should this growth not occur, this reporting unit will likely fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2014 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods.

We will continue to monitor this reporting unit for impairment and note that continued declines in contracted capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in future failure of step one of the goodwill impairment test and may also result in a future impairment of goodwill. If subscription rates and subscribed volumes decline, the estimated future cash flows will decrease from our current estimates. As of December 31, 2014, we estimate that 11% of our future cash flows will be received over the next 10 years, an additional 24% over the following 10 years and 65% in periods thereafter over the remaining useful lives of our storage facilities.

Long-Lived Assets We depreciate or amortize our long-lived and intangible assets over their estimated useful lives. Currently, we have no significant indefinite-lived intangible assets. We assess our long-lived and intangible assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. Impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

We determined that there were no long-lived asset impairments in 2014; however, our Golden Triangle storage facility within midstream operations currently has less than a 5% cushion of its undiscounted cash flows over its book value. Accordingly, if this facility experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of these long-lived assets.

Our agreement in June 2013 to acquire customer relationship intangible assets within our retail operations segment included a provision for the seller to provide an adjustment to the $32 million purchase price for attrition that exceeds historical levels. In January 2015, we received $5 million from the seller that will be reflected as a reduction to our intangible assets on our Consolidated Statements of Financial Position in 2015 and will reduce the amortization for the same amount over the remaining useful life of 13.5 years.

Derivatives and Hedging Activities

The authoritative guidance to determine whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is voluminous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in our assessment of the likelihood of future hedged transactions or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions, and changes in hedge effectiveness may impact the accounting treatment.

The authoritative guidance related to derivatives and hedging requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the Consolidated Statements of Financial Position as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for, and is designated as, a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. We utilize market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

The authoritative accounting guidance requires that changes in the derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance allows derivative gains and losses to offset related results of the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until the hedged transaction occurs in the case of a cash flow hedge. Additionally, the guidance requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

Nicor Gas and Elizabethtown Gas utilize derivative instruments to hedge the price risk for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as accounting hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory commissions, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

We use derivative instruments primarily to reduce the impact to our results of operations due to the risk of changes in the price of natural gas. The fair value of natural gas derivative instruments used to manage our exposure to changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For the derivatives utilized in retail operations and wholesale services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in our results of operations in the period of change. Retail operations records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

Additionally, as required by the authoritative guidance, we are required to classify our derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of our derivative instruments incorporates various factors required under the guidance. These factors include:

- the credit worthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of our nonperformance risk on our liabilities.

We have recorded derivative instrument assets of $287 million at December 31, 2014 and $119 million at December 31, 2013. Additionally, we have recorded derivative liabilities of $93 million at December 31, 2014 and $80 million at December 31, 2013. We recorded gains on our Consolidated Statements of Income of $139 million in 2014 and $10 million in 2012 and losses of $97 million in 2013.

If there is a significant change in the underlying market prices or pricing assumptions we use in pricing our derivative assets or liabilities, we may experience a significant impact on our financial position, results of operations and cash flows. Our derivative and hedging activities are described in further detail in Note 2 and Note 5 to our consolidated financial statements under Item 8 and Item 1, "Business," herein.

Contingencies

Our accounting policies for contingencies cover a variety of activities that are incurred in the normal course of business and generally relate to contingencies for potentially uncollectible receivables, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future.

Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 11 to our consolidated financial statements under Item 8 herein.

Pension and Welfare Plans

Our pension and welfare plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates. We annually review the estimates and assumptions underlying our pension and welfare plan costs and liabilities and update them when appropriate. The critical actuarial assumptions used to develop the required estimates for our pension and welfare plans include the following key factors:

- assumed discount rates;
- expected return on plan assets;
- the market value of plan assets;
- assumed mortality table; and
- assumed health care costs.

The discount rate is utilized in calculating the actuarial present value of our pension and welfare obligations and our annual net pension and welfare costs. When establishing our discount rate, with the assistance of our actuaries, we consider high-grade bond indices. The single equivalent discount rate is derived by applying the appropriate spot rates based on high quality (AA or better) corporate bonds that have a yield higher than the regression mean yield curve, to the forecasted future cash flows in each year for each plan.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and welfare plans costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, it does not affect that year's annual pension or welfare plan cost; rather, this gain or loss reduces or increases future pension or welfare plan costs.

Equity market performance and corporate bond rates have a significant effect on our reported results. For the AGL Pension Plan, market performance affects our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year smoothing weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology, which affects the expected return on plan assets component of pension expense.

In addition, differences between actuarial assumptions and actual plan experience are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation (PBO) or the MRVPA for the AGL Pension Plan. The excess, if any, is amortized over the average remaining service period of active employees.

During 2014, we recorded net periodic benefit costs of $39 million (pre-capitalization) related to our defined pension and welfare benefit plans. We estimate that in 2015, we will record net periodic pension and welfare benefit costs in the range of $45 million to $49 million (pre-capitalization), a $6 million to $10 million increase compared to 2014. In determining our estimated expenses for 2015, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans	Welfare plans
Discount rate	4.2%	4.0%
Expected return on plan assets	7.75%	7.75%

The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal and retirement rates, and longer or shorter life spans of participants. The following table illustrates the effect of changing the critical actuarial assumptions for our pension and welfare plans while holding all other assumptions constant:

Dollars in millions	Percentage-point change in assumption	Increase (decrease) in PBO / APBO	Increase (decrease) in cost
Expected long-term return on plan assets	+ / - 1%	$ - / -	$(9) / 9
Discount rate	+ / - 1%	$(175) / 196	$(14) / 14

During 2014, our actuary gathered industry specific data in order to assess the appropriateness of the mortality rates for different industries and analyzed our industry group mortality experience. Accordingly, in 2014 we changed the mortality table and mortality improvement scales for the calculation of our benefit obligations as of December 31, 2014. This increased our PBO and accumulated projected benefit obligation (APBO) by $26 million and $10 million, respectively, compared to 2013.

See Note 4 and Note 6 to our consolidated financial statements under Item 8 herein for additional information on our pension and welfare plans.

Income Taxes

The determination of our provision for income taxes requires significant judgment, the use of estimates and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We account for income taxes in accordance with authoritative guidance, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some or all of the deferred tax assets will not be realized.

Deferred tax liabilities are estimated based on the expected future tax consequences of items recognized in the financial statements. Additionally, during the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. As a result, we recognize tax liabilities based on estimates of whether additional taxes and interest will be due. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns.

With the sale of Tropical Shipping in the third quarter of 2014, we determined that the cumulative foreign earnings of that business would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash.

For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. In addition, we operate within multiple tax jurisdictions and we are subject to audits in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and, in our opinion, adequate provisions for income taxes have been made for all years reported.

We had a $20 million valuation allowance on $307 million of deferred tax assets ($218 million of long-term and $89 million of current) as of December 31, 2014, reflecting the expectation that a majority of these assets will be realized. Our gross long-term deferred tax liability totaled $1,928 million at December 31, 2014. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our taxes.

We are required to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Additionally, we recognize accrued interest related to uncertain tax positions in interest expense, and penalties in operating expense in the Consolidated Statements of Income. As of December 31, 2014, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Accounting Developments

See "Accounting Developments" in Note 2 to our consolidated financial statements under Item 8 herein.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk results from changes in the fair value of natural gas. Interest rate risk is caused by fluctuations in interest rates related to our portfolio of debt instruments and equity that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. We use derivative instruments to manage these risks. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

Our RMC is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions.

Weather and Natural Gas Price Risks

Distribution Operations Our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it has no natural gas price risk.

Nicor Gas and Elizabethtown Gas enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices for customers. These derivatives are reflected at fair value and are not designated as hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers and therefore have no direct impact on earnings. Realized and unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities until recovered from or credited to our customers.

For our Illinois weather risk associated with Nicor Gas, we have a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather. For more information, see Note 2 to the consolidated financial statements under Item 8 herein.

Retail Operations and Wholesale Services We routinely utilize various types of derivative instruments to mitigate certain natural gas price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. Retail operations and wholesale services also actively manage storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. These hedging instruments are used to substantially protect economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize our exposure to declining operating margins.

Midstream Operations We use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas, conditioning gas and additional volumes of gas used to de-water our caverns (de-water gas) during the construction or expansion of storage facilities. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. Conditioning gas is used to ready a field for use and will be sold in connection with placing the storage facility into service. De-water gas is used to remove water from the cavern in anticipation of commercial service and will be sold after completion of de-watering. We also use derivative instruments for asset optimization purposes.

Consolidated The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the 12 months ended December 31, 2014 and 2013.

	Derivative instruments average values (1) at December 31,	
In millions	**2014**	**2013**
Asset	$152	$107
Liability	101	49

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at December 31,	
In millions	**2014**	**2013**
Asset	$287	$119
Liability	93	80

The following table illustrates the change in the net fair value of our derivative instruments during the 12 months ended December 31, 2014, 2013 and 2012, and provides detail of the net fair value of contracts outstanding as of December 31, 2014, 2013 and 2012.

In millions	**2014**	**2013**	**2012**
Net fair value of derivative instruments outstanding at beginning of period	$(82)	$36	$31
Derivative instruments realized or otherwise settled during period	38	(62)	(61)
Change in net fair value of derivative instruments	105	(56)	66
Net fair value of derivative instruments outstanding at end of period	61	(82)	36
Netting of cash collateral	133	121	69
Cash collateral and net fair value of derivative instruments outstanding at end of period (1)	$194	$39	$105

(1) Net fair value of derivative instruments outstanding includes $3 million premium and associated intrinsic value at December 31, 2014 and 2013, and $4 million at December 31, 2012 associated with weather derivatives.

The sources of our net fair value at December 31, 2014 are as follows.

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through 2015	$(28)	$65
Mature 2016 – 2017	7	18
Mature 2018 – 2019	(1)	-
Total derivative instruments (3)	$(22)	$83

(1) Valued using NYMEX futures prices.
(2) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.
(3) Excludes cash collateral amounts.

VaR Our VaR may not be comparable to that of other entities due to differences in the factors used to calculate VaR. Our VaR is determined on a 95% confidence interval and a 1-day holding period, which means that 95% of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally mitigated. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

Natural gas markets experienced unprecedented levels of high volatility and prices due to the extended extreme cold weather during the first quarter of 2014, resulting in our VaR to be at elevated levels during the quarter as compared to prior periods. We actively managed and monitored the open positions and exposures that were driving the elevated VaR levels to not only remain in compliance with established policies, but to also mitigate the operational risks of not being able to meet customer needs under these extreme conditions. As conditions moderated at the end of the quarter, our period-end VaR was consistent with historical periods. We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period, SouthStar's portfolio of positions for the 12 months ended December 31, 2014, 2013 and 2012 were less than $0.1 million and Sequent had the following VaRs.

In millions	2014	2013	2012
Period end	$4.7	$4.7	$1.8
12-month average	4.3	2.3	2.0
High	19.7	4.9	4.8
Low	1.8	1.2	1.1

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $1.5 billion of variable-rate debt outstanding at December 31, 2014, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $15 million on an annualized basis.

We sometimes utilize interest rate swaps to help us achieve our desired mix of variable to fixed-rate debt. Our variable-rate debt target generally ranges from 20% to 45% of total debt. We may also use forward-starting interest rate swaps and interest rate lock agreements to lock in fixed interest rates on our forecasted issuances of debt. The objective of these hedges is to offset the variability of future payments associated with the interest rate on debt instruments we expect to issue. The gain or loss on the interest rate swaps designated as cash flow hedges is generally deferred in accumulated OCI until settlement, at which point it is amortized to interest expense over the life of the related debt. For additional information, see Note 2 and Note 5 to our consolidated financial statements under Item 8 herein.

During the fourth quarter of 2014, $120 million of our senior notes converted from a fixed interest rate to a LIBOR-based variable interest rate. During the first quarter of 2015, we executed $800 million of fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated debt issuances in 2015 and 2016. We have designated the forward-starting interest rate swaps, which will be settled on the debt issuance dates, as cash flow hedges.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk, as it bills 12 certificated and active Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2014, the four largest Marketers based on customer count accounted for approximately 14% of our consolidated operating margin and 20% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light.

Our gas distribution businesses offer options to help customers manage their bills, such as energy assistance programs for low-income customers and a budget payment plan that spreads gas bills more evenly throughout the year. Customer credit risk has been substantially mitigated at Nicor Gas by the bad debt rider approved by the Illinois Commission in 2010, which provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense included in its rates for the respective year. For Virginia Natural Gas and Chattanooga Gas, we are allowed to recover the gas portion of bad debt write-offs through their gas recovery mechanisms.

Nicor Gas faces potential credit risk in connection with its natural gas sales and procurement activities to the extent a counterparty defaults on a contract to pay for or deliver at agreed-upon terms and conditions. To manage this risk, Nicor Gas maintains credit policies to determine and monitor the creditworthiness of its counterparties. In doing so, Nicor Gas seeks guarantees or collateral, in the form of cash or letters of credit, which limits its exposure to any individual counterparty and enters into netting arrangements to mitigate counterparty credit risk.

Certain of our derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral we post in the normal course of business when our financial instruments are in net liability positions. As of December 31, 2014, for agreements with such features, our distribution operations derivative instruments with liability fair values totaled $44 million, for which we had posted $20 million of collateral to our counterparties.

Retail Operations We obtain credit scores for our firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed our credit threshold. We consider potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, we also assign physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

Wholesale Services We have established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. We also utilize master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. We also use other netting agreements with certain counterparties with whom we conduct significant transactions. Master netting agreements enable us to net certain assets and liabilities by counterparty. We also net across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

Additionally, we may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have investment grade ratings.

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of December 31, 2014, our top 20 counterparties represented approximately 55% of the total counterparty exposure of $665 million, excluding $6 million of customer deposits.

As of December 31, 2014, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions as of December 31.

In millions	Gross receivables 2014	Gross receivables 2013	Gross payables 2014	Gross payables 2013
Netting agreements in place:				
Counterparty is investment grade	$482	$496	$276	$265
Counterparty is non-investment grade	4	-	7	10
Counterparty has no external rating	263	260	494	393
No netting agreements in place:				
Counterparty is investment grade	30	29	-	2
Counterparty has no external rating	-	1	-	1
Amount recorded on Consolidated Statements of Financial Position	$779	$786	$777	$671

We have certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements with our counterparties would have totaled $14 million at December 31, 2014, which would not have a material impact on our consolidated results of operations, cash flows or financial condition.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at 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. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective 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 (COSO). The Company's management is responsible for these financial statements and financial statement schedule, 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. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits 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 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 11, 2015

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our principal executive officer and principal financial officer, management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014, using the criteria described in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework").

Based on our evaluation under the COSO Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 11, 2015

/s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

/s/ Andrew W. Evans
Andrew W. Evans
Executive Vice President and Chief Financial Officer

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - ASSETS

In millions	As of December 31, 2014	2013
Current assets		
Cash and cash equivalents	$31	$81
Short-term investments	8	49
Receivables		
Energy marketing	779	786
Natural gas	391	385
Unbilled revenues	256	268
Other	150	83
Less allowance for uncollectible accounts	35	29
Total receivables, net	1,541	1,493
Inventories		
Natural gas	694	637
Other	22	21
Total inventories	716	658
Derivative instruments	245	99
Prepaid expenses	223	63
Regulatory assets	83	114
Assets held for sale	-	283
Other	43	55
Total current assets	2,890	2,895
Long-term assets and other deferred debits		
Property, plant and equipment	11,552	10,938
Less accumulated depreciation	2,462	2,295
Property, plant and equipment, net	9,090	8,643
Goodwill	1,827	1,827
Regulatory assets	631	705
Intangible assets	125	145
Long-term investments	105	113
Pension assets	97	117
Derivative instruments	42	20
Other	102	85
Total long-term assets and other deferred debits	12,019	11,655
Total assets	$14,909	$14,550

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - LIABILITIES AND EQUITY

In millions, except share amounts	**As of December 31, 2014**	**2013**
Current liabilities		
Short-term debt	$1,175	$1,171
Energy marketing trade payables	777	671
Other accounts payable – trade	312	421
Current portion of long-term debt	200	-
Customer deposits and credit balances	125	136
Regulatory liabilities	112	183
Accrued wages and salaries	97	66
Derivative instruments	88	75
Accrued environmental remediation liabilities	87	70
Accrued taxes	79	85
Accrued interest	53	52
Liabilities held for sale	-	40
Other	114	148
Total current liabilities	3,219	3,118
Long-term liabilities and other deferred credits		
Long-term debt	3,602	3,813
Accumulated deferred income taxes	1,724	1,628
Regulatory liabilities	1,601	1,518
Accrued pension and retiree welfare benefits	525	404
Accrued environmental remediation liabilities	327	377
Other	83	79
Total long-term liabilities and other deferred credits	7,862	7,819
Total liabilities and other deferred credits	11,081	10,937
Commitments, guarantees and contingencies (see Note 11)		
Equity		
Common shareholders' equity		
Common stock, $5 par value; 750,000,000 shares authorized; outstanding: 119,647,149 shares at December 31, 2014 and 118,888,876 shares at December 31, 2013	599	595
Additional paid-in capital	2,087	2,054
Retained earnings	1,312	1,063
Accumulated other comprehensive loss	(206)	(136)
Treasury shares, at cost: 216,523 shares at December 31, 2014 and 2013	(8)	(8)
Total common shareholders' equity	3,784	3,568
Noncontrolling interest	44	45
Total equity	3,828	3,613
Total liabilities and equity	$14,909	$14,550

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

In millions, except per share amounts	**Years ended December 31, 2014**	**2013**	**2012**
Operating revenues (includes revenue taxes of $133 for 2014, $112 for 2013 and $86 for 2012)	$5,385	$4,209	$3,562
Operating expenses			
Cost of goods sold	2,765	2,110	1,583
Operation and maintenance	939	887	816
Depreciation and amortization	380	397	394
Taxes other than income taxes	208	187	159
Nicor merger expenses	-	-	20
Total operating expenses	4,292	3,581	2,972
Gain on disposition of assets	2	11	-
Operating income	1,095	639	590
Other income, net	14	16	24
Interest expense, net	(179)	(170)	(183)
Income before income taxes	930	485	431
Income tax expense	350	177	157
Income from continuing operations	580	308	274
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income	500	313	275
Less net income attributable to the noncontrolling interest	18	18	15
Net income attributable to AGL Resources Inc.	$482	$295	$260
Amounts attributable to AGL Resources Inc.			
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Per common share information			
Basic earnings (loss) per common share			
Continuing operations	$4.73	$2.46	$2.21
Discontinued operations	(0.67)	0.04	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$4.06	$2.50	$2.22
Diluted earnings (loss) per common share			
Continuing operations	$4.71	$2.45	$2.20
Discontinued operations	(0.67)	0.04	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21
Cash dividends declared per common share	$1.96	$1.88	$1.74
Weighted average number of common shares outstanding			
Basic	118.8	117.9	117.0
Diluted	119.2	118.3	117.5

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
In millions	**2014**	**2013**	**2012**
Net income	$500	$313	$275
Other comprehensive income (loss), net of tax			
Retirement benefit plans, net of tax			
Actuarial (loss) gain arising during the period (net of income tax of $48, $46 and $16)	(71)	66	(17)
Prior service cost arising during the period (net of income tax of $1)	-	-	1
Reclassification of actuarial loss to net benefit cost (net of income tax of $6, $10 and $9)	9	15	13
Reclassification of prior service cost to net benefit cost (net of income tax of $1, $2 and $2)	(1)	(3)	(2)
Retirement benefit plans, net	(63)	78	(5)
Cash flow hedges, net of tax			
Net derivative instrument (loss) gain arising during the period (net of income tax of $2, $1 and $-)	(6)	1	(2)
Reclassification of realized derivative (gain) loss to net income (net of income tax of $2, $1 and $3)	(3)	3	6
Cash flow hedges, net	(9)	4	4
Other comprehensive income (loss), net of tax	(72)	82	(1)
Comprehensive income	428	395	274
Less comprehensive income attributable to noncontrolling interest	16	18	15
Comprehensive income attributable to AGL Resources Inc.	**$412**	**$377**	**$259**

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	AGL Resources Inc. Shareholders								
	Common stock								
In millions, except per share amounts	Shares	Amount	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
As of December 31, 2011	**117.0**	**$586**	**$1,989**	**$933**	**$(217)**	**$(7)**	**$21**	**$3,305**
Net income	-	-	-	260	-	-	15	275
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)
Dividends on common stock ($1.74 per share)	-	-	-	(203)	-	-	-	(203)
Distributions to noncontrolling interests	-	-	-	-	-	-	(14)	(14)
Stock granted, share-based compensation, net of forfeitures	-	-	(10)	-	-	-	-	(10)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.6	3	19	-	-	(1)	-	21
Stock-based compensation expense, net of tax	-	-	8	-	-	-	-	8
As of December 31, 2012	**117.9**	**$590**	**$2,015**	**$990**	**$(218)**	**$(8)**	**$22**	**$3,391**
Net income	-	-	-	295	-	-	18	313
Other comprehensive income	-	-	-	-	82	-	-	82
Dividends on common stock ($1.88 per share)	-	-	-	(222)	-	-	-	(222)
Contribution from noncontrolling interest	-	-	-	-	-	-	22	22
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(6)	-	-	-	-	(6)
Stock issued, dividend reinvestment plan	0.3	1	10	-	-	-	-	11
Stock issued, share-based compensation, net of forfeitures	0.7	4	24	-	-	-	-	28
Stock-based compensation expense, net of tax	-	-	11	-	-	-	-	11
As of December 31, 2013	**118.9**	**$595**	**$2,054**	**$1,063**	**$(136)**	**$(8)**	**$45**	**$3,613**
Net income	-	-	-	482	-	-	18	500
Other comprehensive income	-	-	-	-	(70)	-	(2)	(72)
Dividends on common stock ($1.96 per share)	-	-	-	(233)	-	-	-	(233)
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(11)	-	-	-	-	(11)
Stock issued, dividend reinvestment plan	0.2	1	11	-	-	-	-	12
Stock issued, share-based compensation, net of forfeitures	0.5	3	19	-	-	-	-	22
Stock-based compensation expense, net of tax	-	-	14	-	-	-	-	14
As of December 31, 2014	**119.6**	**$599**	**$2,087**	**$1,312**	**$(206)**	**$(8)**	**$44**	**$3,828**

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years ended December 31,		
In millions	**2014**	**2013**	**2012**
Cash flows from operating activities			
Net income	$500	$313	$275
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	380	397	394
Deferred income taxes	201	(16)	157
Change in derivative instrument assets and liabilities	(155)	66	72
Gain on disposition of assets	(2)	(11)	-
Loss (income) from discontinued operations, net of tax	80	(5)	(1)
Changes in certain assets and liabilities			
Energy marketing receivables and trade payables, net	113	(54)	(44)
Accrued expenses	32	39	(28)
Prepaid and miscellaneous taxes	(244)	103	41
Trade payables, other than energy marketing	(81)	89	49
Accrued/deferred natural gas costs	(67)	2	37
Inventories	(58)	41	43
Receivables, other than energy marketing	(55)	(74)	12
Other, net	21	70	(18)
Net cash flow (used in) provided by operating activities of discontinued operations	(10)	11	14
Net cash flow provided by operating activities	655	971	1,003
Cash flows from investing activities			
Expenditures for property, plant and equipment	(769)	(731)	(775)
Dispositions of assets	230	12	-
Acquisitions of assets	-	(154)	-
Other, net	47	8	(6)
Net cash flow used in investing activities of discontinued operations	(13)	(11)	(5)
Net cash flow used in investing activities	(505)	(876)	(786)
Cash flows from financing activities			
Benefit, dividend reinvestment and stock purchase plan	22	33	21
Net issuances (repayments) of commercial paper	4	(206)	56
Dividends paid on common shares	(233)	(222)	(203)
Distribution to noncontrolling interest	(17)	(17)	(14)
Issuance of senior notes	-	494	-
Contribution from noncontrolling interest	-	22	-
Payment of senior notes	-	(225)	-
Proceeds from termination of interest rate swap	-	-	17
Payment of medium-term notes	-	-	(15)
Other, net	-	-	(17)
Net cash flow used in financing activities	(224)	(121)	(155)
Net (decrease) increase in cash and cash equivalents - continuing operations	(51)	(26)	53
Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	-	9
Cash and cash equivalents (including held for sale) at beginning of period	105	131	69
Cash and cash equivalents (including held for sale) at end of period	31	105	131
Less cash and cash equivalents held for sale at end of period	-	24	23
Cash and cash equivalents (excluding held for sale) at end of period	**$31**	**$81**	**$108**
Cash paid (received) during the period for			
Interest	$187	$175	$174
Income taxes	422	120	(37)
Non cash financing transaction			
Refinancing of gas facility revenue bonds	$-	$200	$-

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 - Organization and Basis of Presentation

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our,” the “company,” or “AGL Resources” mean consolidated AGL Resources Inc. and its subsidiaries.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2014 are prepared in accordance with GAAP and under the rules of the SEC. Our consolidated financial statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority owned or otherwise controlled subsidiaries and the accounts of our variable interest entity, SouthStar, for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we primarily use the equity method of accounting and our proportionate share of income or loss is recorded on the Consolidated Statements of Income. See Note 10 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts is probable under the affiliates’ rate regulation process.

In November 2014, we filed a 2013 Form 10-K/A to revise our financial statements and other affected disclosures for items related to the recognition of revenues for certain of our regulatory infrastructure programs and the amortization of our intangible assets as filed in our 2013 Form 10-K. Our prior period financial statements reflect the revised amounts reported in our 2013 Form 10-K/A.

In September 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position, and the financial results of these businesses are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in the following notes, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified into our “other” non-reportable segments. See Note 14 for additional information.

Certain amounts from prior periods have been reclassified to conform to the current-period presentation. The reclassifications had no material impact on our prior-period balances.

Note 2 - Significant Accounting Policies and Methods of Application

Cash and Cash Equivalents

Our cash and cash equivalents primarily consist of cash on deposit, money market accounts and certificates of deposit held by domestic subsidiaries with original maturities of three months or less. As of December 31, 2013, $24 million of cash and cash equivalents within our Consolidated Statements of Financial Position held by Tropical Shipping were excluded from cash and cash equivalents and included in assets held for sale. Prior to closing the sale, cash and short-term investments that were held in off-shore accounts were repatriated. See Note 12 and Note 14 for additional information on our income taxes on the cumulative foreign earnings for which no tax liability had previously been recorded.

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements that enable our wholesale services segment to net receivables and payables by counterparty upon settlement. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale services’ counterparties are settled net, they are recorded on a gross basis in our Consolidated Statements of Financial Position as energy marketing receivables and energy marketing payables.

Our wholesale services segment has trade and credit contracts that contain minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale services would need to post collateral to continue transacting business with some of its counterparties. To date, our credit ratings have exceeded the minimum requirements. As of December 31, 2014 and 2013, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status would not have had a material impact to our consolidated results of operations, cash flows or financial condition. If such collateral were not posted, wholesale services’ ability to continue transacting business with these counterparties would be negatively impacted.

Wholesale services has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is generally concentrated in 20 of its counterparties and is measured by 30-day receivable exposure plus forward exposure. We evaluate the credit risk of our counterparties using an S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being equivalent to D/Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios. As of December 31, 2014, our top 20 counterparties represented 55%, or $367 million, of our total counterparty exposure and had a weighted average S&P equivalent rating of A-.

We have established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. When wholesale services is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty combined with a reasonable measure of our credit risk. Wholesale services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Receivables and Allowance for Uncollectible Accounts

Our other trade receivables consist primarily of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and our accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience and other factors. For our remaining receivables, if we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the receivable balance to the amount we reasonably expect to collect. If circumstances change, our estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, customer deposits and general economic conditions. Customers' accounts are written off once we deem them to be uncollectible.

Nicor Gas Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year. See Note 3 for additional information on the bad debt rider.

Atlanta Gas Light Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 12 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings and collections. We obtain credit security support in an amount equal to no less than two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Inventories

For our regulated utilities, except Nicor Gas, our natural gas inventories and the inventories we hold for Marketers in Georgia are carried at cost on a WACOG basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory. Atlanta Gas Light also retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand. See Note 11 for information regarding a regulatory filing by Atlanta Gas Light related to gas inventory.

Nicor Gas' inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of goods sold at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of goods sold at the actual LIFO cost of the layers liquidated. Since the cost of gas, including inventory costs, is charged to customers without markup, subject to Illinois Commission review, LIFO liquidations have no impact on net income. At December 31, 2014, the Nicor Gas LIFO inventory balance was $141 million. Based on the average cost of gas purchased in December 2014, the estimated replacement cost of Nicor Gas' inventory at December 31, 2014 was $346 million, which exceeded the LIFO cost by $205 million. During 2014, we liquidated 6.8 Bcf of our LIFO-based inventory at an average cost per million cubic feet (Mcf) of $3.98. For gas purchased in 2014, our average cost per Mcf was $1.33 higher than the average LIFO liquidation rate. Applying LIFO cost in valuing the liquidation, as opposed to using the average gas purchase cost, had the effect of decreasing the cost of gas in 2014 by $9 million.

Our retail operations, wholesale services and midstream operations segments carry inventory at the lower of cost or market value, where cost is determined on a WACOG basis. For these segments, we evaluate the weighted average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the

WACOG are other than temporary. As indicated in the following LOCOM table, for any declines considered to be other than temporary, we record these pre-tax adjustments to our Consolidated Statements of Income to reduce the weighted average cost of the natural gas inventory to market value.

In millions	2014	2013	2012
Retail operations	$4	$1	$3
Wholesale services (1)	73	8	19
Midstream operations	-	-	1
Total	$77	$9	$23

(1) The increase in 2014 was due to a significant decline in natural gas prices in December 2014.

Additionally, we have $17 million of inventory at wholesale services that is currently inaccessible due to operational issues at a third-party storage facility. The owner of the storage facility is working to resolve these issues. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

At midstream operations, mechanical integrity tests and engineering studies are periodically performed on the storage facilities in accordance with certain state regulatory requirements. During 2014, an engineering study and mechanical integrity tests were performed at one of our storage facilities, identifying a lower amount of working gas capacity that is the result of naturally occurring shrinkage of the storage caverns. Further, based on the lower capacity and an analysis of the volume of natural gas stored in the facility, we recorded natural gas costs to true-up the amount of retained fuel at this facility in the amount of $10 million. Our other storage facilities at midstream operations were not impacted.

Regulated Operations

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for estimated expenditures that have not yet been incurred. Generally, regulatory assets and regulatory liabilities are amortized into our Consolidated Statements of Income over the period authorized by the regulatory commissions.

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents, and derivative assets and liabilities. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate fair value. Our nonfinancial assets and liabilities include pension and other retirement benefits. See Note 4 for additional fair value disclosures.

As defined in the authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 items consist of exchange-traded derivatives, money market funds and certain retirement plan assets.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. We obtain market price data from multiple sources in order to value some of our Level 2 transactions and this data is representative of transactions that occurred in the marketplace. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options and certain retirement plan assets.

Level 3 Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management's best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. Our Level 3 assets, liabilities and any applicable transfers are primarily related to our pension and welfare benefit plan assets as described in Note 4 and Note 6. We determine both transfers into and out of Level 3 using values at the end of the interim period in which the transfer occurred.

The authoritative guidance related to fair value measurements and disclosures also includes a two-step process to determine whether the market for a financial asset is inactive or a transaction is distressed. Currently, this authoritative guidance does not affect us, as our derivative instruments are traded in active markets.

Derivative Instruments

Our policy is to classify derivative cash flows and gains and losses within the same financial statement category as the hedged item, rather than by the nature of the instrument.

Fair Value Hierarchy Derivative assets and liabilities are classified in their entirety into the previously described fair value hierarchy levels based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The measurement of fair value incorporates various factors required under the guidance. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our own nonperformance risk on our liabilities. To mitigate the risk that a counterparty to a derivative instrument defaults on settlement or otherwise fails to perform under contractual terms, we have established procedures to monitor the creditworthiness of counterparties, seek guarantees or collateral backup in the form of cash or letters of credit and, in most instances, enter into netting arrangements. See Note 4 for additional fair value disclosures.

Netting of Cash Collateral and Derivative Assets and Liabilities under Master Netting Arrangements We maintain accounts with brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts.

We have elected to net derivative assets and liabilities under master netting arrangements on our Consolidated Statements of Financial Position. With that election, we are also required to offset cash collateral held in our broker accounts with the associated net fair value of the instruments in the accounts. See Note 4 for additional information about our cash collateral.

Natural Gas and Weather Derivative Instruments The fair value of the natural gas derivative instruments that we use to manage exposures arising from changing natural gas prices and weather risk reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative instruments. See Note 5 for additional derivative disclosures.

Distribution Operations Nicor Gas, subject to review by the Illinois Commission, and Elizabethtown Gas, in accordance with a directive from the New Jersey BPU, enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices. In accordance with regulatory requirements, any realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. As previously noted, such derivative instruments are reported at fair value each reporting period in our Consolidated Statements of Financial Position. Hedge accounting is not elected and, in accordance with accounting guidance pertaining to rate-regulated entities, unrealized changes in the fair value of these derivative instruments are deferred or accrued as regulatory assets or liabilities until the related revenue is recognized.

For our Illinois weather risk associated with Nicor Gas, we have a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois and is carried at intrinsic value. We will continue to use available methods to mitigate our exposure to weather in Illinois.

Retail Operations We have designated a portion of our derivative instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period that the underlying hedged item is recognized in earnings.

We currently have minimal hedge ineffectiveness, which occurs when the gains or losses on the hedging instrument more than offset the losses or gains on the hedged item. Any cash flow hedge ineffectiveness is recorded in our Consolidated Statements of Income in the period in which it occurs. We have not designated the remainder of our derivative instruments as hedges for accounting purposes and, accordingly, we record changes in the fair values of such instruments within cost of goods sold in our Consolidated Statements of Income in the period of change.

We also enter into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non exchange-traded options are accounted for using the intrinsic value method and do not qualify for hedge accounting designation. Changes in the intrinsic value for non exchange-traded contracts are also reflected in operating revenues in our Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the current market price we pay to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures and OTC contracts to sell natural gas at that future price to substantially protect the operating margin we will ultimately realize when the stored natural gas is sold. We also enter into transactions to secure transportation capacity between delivery points in order to serve our customers and various markets. We use NYMEX futures and OTC contracts to capture the price differential or spread between the locations served by the capacity in order to substantially protect the operating margin we will ultimately realize when we physically flow natural gas between delivery points. These contracts generally meet the definition of derivatives and are carried at fair value in our Consolidated Statements of Financial Position, with changes in fair value recorded in operating revenues in our Consolidated Statements of Income in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage and transportation portfolio. We incur monthly demand charges for the contracted storage and transportation capacity, and payments associated with asset management agreements, and we recognize these demand charges and payments in our Consolidated Statements of Income in the period they are incurred. This difference in accounting methods can result in volatility in our reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

Debt We estimate the fair value of debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we consider our currently assigned ratings for unsecured debt and the secured rating for the Nicor Gas first mortgage bonds.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2014 and 2013 is provided in the following table.

In millions	2014	2013
Transportation and distribution	$9,105	$8,371
Storage facilities	1,202	1,170
Other	919	854
Construction work in progress	326	543
Total PP&E, gross	11,552	10,938
Less accumulated depreciation	2,462	2,295
Total PP&E, net	$9,090	$8,643

Distribution Operations Our natural gas utilities' PP&E consists of property and equipment that is currently in use, being held for future use and currently under construction. We report PP&E at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs;
- AFUDC; and,
- Nicor Gas' pad gas - the portion considered to be non-recoverable is recorded as depreciable PP&E, while the portion considered to be recoverable is recorded as non-depreciable PP&E.

We recognize no gains or losses on depreciable utility property that is retired or otherwise disposed, as required under the composite depreciation method. Such gains and losses are ultimately refunded to, or recovered from, customers through future rate adjustments. Our natural gas utilities also hold property, primarily land; this is not presently used and useful in utility operations and is not included in rate base. Upon sale, any gain or loss is recognized in other income.

Retail Operations, Wholesale Services, Midstream Operations and Other PP&E includes property that is in use and under construction, and we report it at cost. We record a gain or loss within operation and maintenance expense for retired or otherwise disposed-of property. Natural gas in salt-dome storage at Jefferson Island and Golden Triangle that is retained as pad gas is classified as non-depreciable PP&E and is carried at cost. Central Valley has two types of pad gas in its depleted reservoir storage facility: The first is non-depreciable PP&E, which is carried at cost, and the second is non-recoverable, over which we have no contractual ownership.

On April 11, 2014, we entered into two arrangements associated with the Dalton Pipeline. The first was a construction and ownership agreement through which we will have a 50% undivided ownership interest in the 106 mile Dalton Pipeline that will be constructed in Georgia and serve as an extension of the Transco natural gas pipeline system into northwest Georgia. We also entered into an agreement to lease our 50% undivided ownership in the Dalton Pipeline once it is placed in service. The lease payments to be received are $26 million annually for an initial term of 25 years. The lessee will be responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff. Engineering design work has commenced and construction is expected to begin in the second quarter of 2016 with a targeted completion date in the second quarter of 2017. The capacity from this pipeline will further enhance system reliability as well as provide access to a more diverse supply of natural gas.

Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property. More information on our rates used and the rate method is provided in the following table.

	2014	2013	2012
Atlanta Gas Light (1)	2.3%	2.6%	2.6%
Chattanooga Gas (1)	2.5%	2.5%	2.5%
Elizabethtown Gas (2)	2.5%	2.4%	2.4%
Elkton Gas (2)	2.8%	2.4%	2.4%
Florida City Gas (2)	3.9%	3.8%	3.9%
Nicor Gas (2) (3)	3.1%	3.1%	4.1%
Virginia Natural Gas (1)	2.5%	2.5%	2.5%

(1) Average composite straight-line depreciation rates for depreciable property, excluding transportation equipment, which may be depreciated in excess of useful life and recovered in rates.
(2) Composite straight-line depreciation rates.
(3) In October 2013, the Illinois Commission approved a composite depreciation rate of 3.07%. The depreciation rate was effective as of August 30, 2013, the date the depreciation study was filed, and had the effect of reducing our 2014 and 2013 depreciation expense by $51 million and $19 million, respectively.

For our non-regulated segments, we compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets.

In years	Estimated useful life
Transportation equipment	5 – 10
Storage caverns	40 – 60
Other	up to 40

AFUDC and Capitalized Interest

Atlanta Gas Light, Nicor Gas, Chattanooga Gas and Elizabethtown Gas are authorized by applicable state regulatory agencies or legislatures to capitalize the cost of debt and equity funds as part of the cost of PP&E construction projects in our Consolidated Statements of Financial Position. The capital expenditures of our other three utilities do not qualify for AFUDC treatment. More information on our authorized or actual AFUDC rates is provided in the following table.

	2014	2013	2012
Atlanta Gas Light	8.10%	8.10%	8.10%
Nicor Gas (1)	0.24%	0.31%	0.36%
Chattanooga Gas	7.41%	7.41%	7.41%
Elizabethtown Gas (1)	0.44%	0.41%	0.51%
AFUDC (*in millions*) (2)	$7	$18	$8

(1) Variable rate is determined by FERC method of AFUDC accounting.
(2) Amount recorded in the Consolidated Statements of Income.

Asset Retirement Obligations

We record a liability at fair value for an asset retirement obligation (ARO) when a legal obligation to retire the asset has been incurred, with an offsetting increase to the carrying value of the related asset. Accretion of the ARO due to the passage of time is recorded as an operating expense. We have recorded an ARO of $3 million at December 31, 2014 and 2013 principally for our storage facilities. For our distribution PP&E, we cannot reasonably estimate the fair value of this obligation because we have determined that we have insufficient internal or industry information to reasonably estimate the potential settlement dates or costs.

Impairment of Assets

Our goodwill is not amortized, but is subject to an annual impairment test. Our other long-lived assets, including our finite-lived intangible assets, require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of the recoverability of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors.

Goodwill We perform an annual goodwill impairment test on our reporting units that contain goodwill during the fourth quarter of each year, or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, the income approach and the market approach, using assumptions consistent with a market participant's perspective.

Under the income approach, fair value is estimated based on the present value of estimated future cash flows discounted at an appropriate risk-free rate that takes into consideration the time value of money, inflation and the risks inherent in ownership of the business being valued. The cash flow estimates contain a degree of uncertainty, and changes in the projected cash flows could significantly increase or decrease the estimated fair value of a reporting unit. For the regulated reporting units, a fair recovery of, and return on, costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach include the return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, current and future rates charged for contracted capacity and a discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area. The estimated rates we will charge to customers for capacity in the storage caverns were based on internal and external rate forecasts.

Under the market approach, fair value is estimated by applying multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry, when available, to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

We weight the results of the two valuation approaches to estimate the fair value of each reporting unit. Our goodwill impairment testing also develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions that are subjective in nature and inherent to a discounted cash flows calculation.

The significant assumptions that drive the estimated values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC) and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment, as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2014 indicated that the estimated fair values of all but one of our reporting units with goodwill were in excess of the carrying values by approximately 30% to over 600%, and were not at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of our storage and fuels reporting unit with $14 million of goodwill, exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2023 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year off of which we estimated the terminal value. In the terminal year, we assumed a long-term earnings growth rate of 2.5%, which is consistent with our 2013 annual goodwill impairment test, and we believe is appropriate given the current economic and industry specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2013 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next nine years. Should this growth not occur, this reporting unit may fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2014 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods.

We will continue to monitor this reporting unit for impairment and note that continued declines in capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in a future impairment of goodwill. The amounts of goodwill as of December 31, 2014 and 2013 are provided below. In 2013, our goodwill increased by $51 million for an acquisition in our retail operations segment. For 2013, the goodwill at Tropical Shipping was classified as held for sale. See Note 14 for additional information.

In millions	**Distribution operations**	**Retail operations**	**Wholesale services**	**Midstream operations**	**Other**	**Consolidated**
Goodwill - December 31, 2014 and 2013	$1,640	$173	$-	$14	$-	$1,827

Long-Lived Assets We depreciate or amortize our long-lived assets and other intangible assets over their useful lives. We have no significant indefinite-lived intangible assets. These long-lived assets and other intangible assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through expected future cash flows. Impairment is indicated if the carrying amount of the long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

We determined that there were no long-lived asset impairments in 2014; however, our Golden Triangle storage facility within midstream operations currently has less than a 5% cushion of its undiscounted cash flows over its book value. Accordingly, if it experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of these long-lived assets. We will continue to monitor the storage assets in midstream operations. In 2013, we recorded an $8 million loss related to Sawgrass Storage.

Intangible Assets Our intangible assets within our retail operations segment are presented in the following table and represent the estimated fair value at the date of acquisition of the acquired intangible assets in our businesses. As indicated previously, we perform an impairment review when impairment indicators are present. If present, we first determine whether the carrying amount of the asset is recoverable through the undiscounted future cash flows expected from the asset. If the carrying amount is not recoverable, we measure the impairment loss, if any, as the amount by which the carrying amount of the asset exceeds its fair value.

	Weighted average amortization period	**December 31, 2014**			**December 31, 2013**		
In millions	(in years)	**Gross**	**Accumulated amortization**	**Net**	**Gross**	**Accumulated amortization**	**Net**
Customer relationships	13	$130	$(42)	$88	$130	$(25)	$105
Trade names	13	45	(8)	37	45	(5)	40
Total		$175	$(50)	$125	$175	$(30)	$145

We amortize these intangible assets in a manner in which the economic benefits are consumed utilizing the undiscounted cash flows that were used in the determination of their fair values. Amortization expense was $20 million in 2014, $18 million in 2013 and $13 million in 2012. Amortization expense for the next five years is as follows:

In millions	**Amortization Expense**
2015	$17
2016	15
2017	14
2018	13
2019	11

Accounting for Retirement Benefit Plans

We recognize the funded status of our plans as an asset or a liability on our Consolidated Statements of Financial Position, measuring the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We generally recognize, as a component of OCI, the changes in funded status that occurred during the year that are not yet recognized as part of net periodic benefit cost. Because substantially all of its retirement costs are recoverable through base rates, Nicor Gas defers the change in funded status that would normally be charged or credited to comprehensive income to a regulatory asset or liability until the period in which the costs are included in base rates, in accordance with the authoritative guidance for rate-regulated entities. The assets of our retirement plans are measured at fair value within the funded status and are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement.

In determining net periodic benefit cost, the expected return on plan assets component is determined by applying our expected return on assets to a calculated asset value, rather than to the fair value of the assets as of the end of the previous fiscal year. For more information, see Note 6. In addition, we have elected to amortize gains and losses caused by actual experience that differs from our assumptions into subsequent periods. The amount to be amortized is the amount of the cumulative gain or loss as of the beginning of the year, excluding those gains and losses not yet reflected in the calculated value, that exceeds 10 percent of the greater of the benefit obligation or the calculated asset value; and the amortization period is the average remaining service period of active employees.

Taxes

Income Taxes The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal difference between net income and taxable income relates to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other temporary differences as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position.

We have current and deferred income taxes in our Consolidated Statements of Income. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense is generally equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

Accumulated Deferred Income Tax Assets and Liabilities As noted above, we report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure these deferred income tax assets and liabilities using enacted income tax rates.

With the sale of Tropical Shipping in the third quarter of 2014, we determined that the cumulative foreign earnings of that business would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash. Refer to Note 14 for additional information.

Income Tax Benefits The authoritative guidance related to income taxes requires us to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Uncertain Tax Positions We recognize accrued interest related to uncertain tax positions in interest expense and penalties in operating expense in our Consolidated Statements of Income.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. However, we do collect and remit various other taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position. In other instances, we are allowed to recover from customers other taxes that are imposed upon us. We record such taxes as operating expenses and record the corresponding customer charges as operating revenues.

Revenues

Distribution operations We record revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial and industrial end-use customer's distribution costs. Additionally, as required by the Georgia Commission, Atlanta Gas Light bills Marketers for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable (SFV) charge, which reflects the historic volumetric usage pattern for the entire residential class. Generally, this seasonal rate design results in billing the Marketers a higher capacity charge in the winter months and a lower charge in the summer months, which impacts our operating cash flows. However, this seasonal billing requirement does not impact our revenues, which are recognized on a straight-line basis, because the associated rate mechanism ensures that we ultimately collect the full annual amount of the SFV charges.

All of our utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas contain WNAs that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNAs have the effect of reducing customer bills when winter weather is colder-than-normal and increasing customer bills when weather is warmer-than-normal. In addition, the tariffs for Virginia Natural Gas, Chattanooga Gas and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage.

Revenue Taxes We charge customers for gas revenue and gas use taxes imposed on us and remit amounts owed to various governmental authorities. Our policy for gas revenue taxes is to record the amounts charged by us to customers, which for some taxes includes a small administrative fee, as operating revenues, and to record the related taxes imposed on us as operating expenses in our Consolidated Statements of Income. Our policy for gas use taxes is to exclude these taxes from revenue and expense, aside from a small administrative fee that is included in operating revenues as the tax is imposed on the customer. As a result, the amount recorded in operating revenues will exceed the amount recorded in operating expenses by the amount of administrative fees that are retained by the company. Revenue taxes included in operating expenses were $130 million in 2014, $110 million in 2013 and $85 million in 2012.

Retail operations Revenues from natural gas sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the most recent meter reading date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

We recognize revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. We recognize revenues for warranty and repair contracts on a straight-line basis over the contract term. Revenues for maintenance services are recognized at the time such services are performed.

Wholesale services Revenues from energy and risk management activities are required under authoritative guidance to be netted with the associated costs. Profits from sales between segments are eliminated and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under authoritative guidance related to derivatives and hedging are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are required to be presented net in revenue.

Midstream operations We record operating revenues for storage and transportation services in the period in which volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at fixed market-based rates. We recognize our park and loan revenues ratably over the life of the contract.

Cost of Goods Sold

Distribution operations Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, we charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. In accordance with the authoritative guidance for rate-regulated entities, we defer or accrue (that is, include as an asset or liability in the Consolidated Statements of Financial Position and exclude from, or include in, the Consolidated Statements of Income, respectively) the difference between the actual cost of goods sold and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. For more information, see Note 3.

Retail operations Our retail operations customers are charged for actual or estimated natural gas consumed. Within our cost of goods sold, we also include costs of fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and gains and losses associated with certain derivatives. Costs to service our warranty and repair contract claims and costs associated with the installation of HVAC equipment are recorded to cost of goods sold.

Operating Leases

We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with authoritative guidance related to leases. This accounting treatment does not affect the future annual operating lease cash obligations. For more information, see Note 11.

Other Income

Our other income is detailed in the following table. For more information on our equity investment income, see Note 10.

In millions	**2014**	**2013**	**2012**
Equity investment income	$8	$3	$13
AFUDC - equity	5	12	6
Other, net	1	1	5
Total other income	$14	$16	$24

Earnings Per Common Share

We compute basic earnings per common share attributable to AGL Resources Inc. common shareholders by dividing our net income attributable to AGL Resources Inc. by the daily weighted average number of common shares outstanding. Diluted earnings per common share attributable to AGL Resources Inc. common shareholders reflect the potential reduction in earnings per common share attributable to AGL Resources Inc. common shareholders that occurs when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options award programs. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance criteria and/or time-based criteria. The future issuance of shares underlying the outstanding stock options depends on whether the market price of the common shares underlying the options exceeds the respective exercise prices of the stock options.

The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented as if performance units currently earned under the plan ultimately vest and as if stock options currently exercisable at prices below the average market prices are exercised.

In millions (except per share amounts)	**2014**	**2013**	**2012**
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Denominator:			
Basic weighted average number of common shares outstanding (1)	118.8	117.9	117.0
Effect of dilutive securities	0.4	0.4	0.5
Diluted weighted average number of common shares outstanding (2)	119.2	118.3	117.5
Basic earnings per common share			
Continuing operations	$4.73	$2.46	$2.21
Discontinued operations	(0.67)	0.04	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$4.06	$2.50	$2.22
Diluted earnings per common share (2)			
Continuing operations	$4.71	$2.45	$2.20
Discontinued operations	(0.67)	0.04	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21

(1) Daily weighted average shares outstanding.

(2) There were no outstanding stock options excluded from the computation of diluted earnings per common share attributable to AGL Resources Inc. for any of the periods presented because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price.

Sale of Compass Energy

On May 1, 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers, within our wholesale services segment. We received an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain ($5 million net of tax). Under the terms of the purchase and sale agreement, we were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. The remaining $5 million of contingent cash consideration was to be received from the buyer annually over a five-year earn out period based upon the financial performance of Compass Energy. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received $4 million, resulting in the recognition of a $3 million gain. We have a five-year agreement through April 2018 to supply natural gas to our former customers. As a result of our continued involvement, the sale of Compass Energy did not meet the criteria for treatment as a discontinued operation in 2014. Under the new accounting guidance, which became effective for us on January 1, 2015, the sale of Compass Energy is not considered a strategic shift in operations and would not be reflected as a discontinued operation if we were to terminate our continued involvement in the future.

Non-Wholly Owned Entities

We hold ownership interests in a number of business ventures with varying ownership structures. We evaluate all of our partnership interests and other variable interests to determine if each entity is a variable interest entity (VIE), as defined in the authoritative accounting guidance. If a venture is a VIE for which we are the primary beneficiary, we consolidate the assets, liabilities and results of operations of the entity. We reassess our conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events under the guidance. We have concluded that the only venture that we are required to consolidate as a VIE, as we are the primary beneficiary, is SouthStar. On our Consolidated Statements of Financial Position, we recognize Piedmont's share of the non-wholly owned entity as a separate component of equity entitled "noncontrolling interest." Piedmont's share of current operations is reflected in "net income attributable to the noncontrolling interest" on our Consolidated Statements of Income. The consolidation of SouthStar has no effect on our calculation of basic or diluted earnings per common share amounts, which are based upon net income attributable to AGL Resources Inc.

For entities that are not determined to be VIEs, we evaluate whether we have control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under our control are consolidated, and entities over which we can exert significant influence, but do not control, are accounted for under the equity method of accounting. However, we also invest in partnerships and limited liability companies that maintain separate ownership accounts. All such investments are required to be accounted for under the equity method unless our interest is so minor that there is virtually no influence over operating and financial policies, as are all investments in joint ventures.

Investments accounted for under the equity method are included in long-term investments on our Consolidated Statements of Financial Position, and the equity income is recorded within other income on our Consolidated Statements of Income and was immaterial for all periods presented. For additional information, see Note 10.

Acquisitions

On January 31, 2013, our retail operations segment acquired approximately 500,000 service contracts and certain other assets from NiSource Inc. for $122 million. These service contracts provide home warranty protection solutions and energy efficiency leasing solutions to residential and small business utility customers and complement the retail business acquired in the Nicor merger. Intangible assets related to this acquisition are primarily customer relationships of $46 million and trade names of $16 million. These intangible assets are being amortized over approximately 14 years for customer relationships and 10 years for trade names. The final allocation of the purchase price to the fair value of assets acquired and liabilities assumed is presented in the following table:

In millions	
Current assets	$3
PP&E	12
Goodwill	51
Intangible assets	62
Current liabilities	(6)
Total purchase price	$122

On June 30, 2013, our retail operations segment acquired approximately 33,000 residential and commercial energy customer relationships in Illinois for $32 million. These customer relationships have been recorded as an intangible asset and are being amortized over 15 years.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our rate-regulated subsidiaries, uncollectible accounts and other allowances for contingent losses, goodwill and other intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. We evaluate our estimates on an ongoing basis and our actual results could differ from our estimates.

Accounting Developments

In April 2014, the FASB issued authoritative guidance related to reporting discontinued operations. The guidance generally raises the threshold for disposals to qualify as discontinued operations and requires new disclosures of both discontinued operations and certain other material disposals that do not meet the definition of a discontinued operation. The guidance was effective for us prospectively beginning January 1, 2015. It had no impact on our accounting for the sale of Tropical Shipping. There was no impact on January 1, 2015, nor is there any reason we would expect this guidance to have a material impact on our consolidated financial statements in the foreseeable future.

In May 2014, the FASB issued an update to authoritative guidance related to revenue from contracts with customers. The update replaces most of the existing guidance with a single set of principles for recognizing revenue from contracts with customers. The guidance will be effective for us beginning January 1, 2017. Early adoption is not permitted. The new guidance must be applied retrospectively to each prior period presented or via a cumulative effect upon the date of initial application. We have not yet determined the impact of this new guidance, nor have we selected a transition method.

In June 2014, the FASB issued an update to authoritative guidance related to accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance will be effective for us beginning January 1, 2016, and it will have no impact on our consolidated financial statements for our existing share-based plans.

Note 3 – Regulated Operations

Our regulatory assets and liabilities reflected within our Consolidated Statements of Financial Position as of December 31 are summarized in the following table.

In millions	2014	2013
Regulatory assets		
Recoverable ERC	$49	$45
Recoverable pension and retiree welfare benefit costs	12	9
Recoverable seasonal rates	10	10
Deferred natural gas costs	3	1
Other	9	49
Total regulatory assets - current	83	114
Recoverable ERC	326	433
Recoverable pension and retiree welfare benefit costs	110	99
Long-term debt fair value adjustment	74	82
Recoverable regulatory infrastructure program costs	69	55
Other	52	36
Total regulatory assets - long-term	631	705
Total regulatory assets	$714	$819
Regulatory liabilities		
Bad debt over collection	$33	$41
Accrued natural gas costs	27	92
Accumulated removal costs	25	27
Other	27	23
Total regulatory liabilities - current	112	183
Accumulated removal costs	1,520	1,445
Regulatory income tax liability	34	27
Unamortized investment tax credit	22	26
Bad debt over collection	12	17
Other	13	3
Total regulatory liabilities - long-term	1,601	1,518
Total regulatory liabilities	$1,713	$1,701

Base rates are designed to provide the opportunity to recover cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during future rate proceedings. We are not aware of evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs consistent with our historical recoveries.

In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income. Additionally, while some regulatory liabilities would be written off, others would continue to be recorded as liabilities, but not as regulatory liabilities.

Although the natural gas distribution industry is competing with alternative fuels, primarily electricity, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under the guidance remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider or proceeding. The regulatory liabilities that do not represent revenue collected from customers for expenditures that have not yet been incurred are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base used to periodically set base rates.

The majority of our regulatory assets and liabilities listed in the preceding table are included in base rates except for the regulatory infrastructure program costs, ERC, bad debt over collection, natural gas costs and energy efficiency costs, which are recovered through specific rate riders on a dollar-for-dollar basis. The rate riders that authorize the recovery of regulatory infrastructure program costs and natural gas costs include both a recovery of cost and a return on investment during the recovery period. Nicor Gas' rate riders for environmental costs and energy efficiency costs provide a return of investment and expense including short-term interest on reconciliation balances. However, there is no interest associated with the under or over collections of bad debt expense.

Nicor Gas' pension and retiree welfare benefit costs have historically been considered in rate proceedings in the same period they are accrued under GAAP. As a regulated utility, Nicor Gas expects to continue rate recovery of the eligible costs of these defined benefit retirement plans and, accordingly, associated changes in the funded status of Nicor Gas' plans have been deferred as a regulatory asset or liability until recognized in net income, instead of being recognized in OCI. The Illinois Commission presently does not allow Nicor Gas the opportunity to earn a return on its recoverable retirement benefit costs. Such costs are expected to be recovered over a period of approximately 10 years. The regulatory assets related to debt are also not included in rate base, but the costs are recovered over the term of the debt through the authorized rate of return component of base rates.

Unrecognized Ratemaking Amounts The following table illustrates our authorized ratemaking amounts that are not recognized in our Consolidated Statements of Financial Position. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs. These amounts will be recognized as revenues in our financial statements in the periods they are collected in rates from our customers.

In millions	**Atlanta Gas Light**	**Virginia Natural Gas**	**Elizabethtown Gas**	**Total**
December 31, 2014	$113	$12	$2	$127
December 31, 2013	80	12	1	93

Natural Gas Costs We charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms established by the state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. We defer or accrue the difference between the actual cost of gas and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities.

Environmental Remediation Costs We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites, substantially all of which is related to our MGP sites. The ERC assets and liabilities are associated with our distribution operations segment and remediation costs are generally recoverable from customers through rate mechanisms approved by regulators. Accordingly, both costs incurred to remediate the former MGP sites, plus the future estimated cost recorded as liabilities, net of amounts previously collected, are recognized as a regulatory asset until recovered from customers.

Our ERC liabilities are estimates of future remediation costs for investigation and cleanup of our current and former operating sites that are contaminated. These estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, on an undiscounted basis. These estimates contain various assumptions, which we refine and update on an ongoing basis. These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, legal expenses or other costs for which we may be held liable but for which we cannot reasonably estimate an amount.

Our accrued ERC are not regulatory liabilities; however, they are deferred as a corresponding regulatory asset until the costs are recovered from customers. These recoverable ERC assets are a combination of accrued ERC liabilities and recoverable cash expenditures for investigation and cleanup costs. We primarily recover these deferred costs through three rate riders that authorize dollar-for-dollar recovery. We expect to collect $49 million in revenues over the next 12 months, which is reflected as a current regulatory asset. We recovered $51 million in 2014, $24 million in 2013 and $13 million in 2012 from our ERC rate riders. The following table provides more information on the costs related to remediation of our current and former operating sites.

In millions	**# of sites**	**Probabilistic model cost estimates** (1)	**Engineering estimates** (1)	**Amount recorded**	**Expected costs over next 12 months**	**Cost recovery period**
Illinois (2)	26	$205 - $462	$30	$230	$41	As incurred
New Jersey	6	105 - 177	14	118	16	7 years
Georgia and Florida	13	40 - 81	15	56	21	5 years
North Carolina (3)	1	n/a	10	10	9	No recovery
Total	46	$350 - $720	$69	$414 (4)	$87	

(1) The year-end ERC cost estimates were completed as of November 30, 2014. The liability recorded reflects a reduction of these cost estimates for expenses incurred during December.

(2) Nicor Gas is responsible in whole or in part for 26 MGP sites, of which two sites have been remediated and their use is no longer restricted by the environmental condition of the property. Nicor Gas and Commonwealth Edison Company are parties to an agreement to cooperate in cleaning up residue at 23 of the sites listed. Nicor Gas' allocated share of cleanup costs for these sites is 52%.

(3) We have no regulatory recovery mechanism for the site in North Carolina. Therefore, there is no amount included within our regulatory assets and changes in estimated costs are recognized in income in the period of change.

(4) Decrease of $33 million from December 31, 2013 primarily relates to lower engineering cost estimates for work completed during 2014, partially offset by a scope increase required by the Georgia Environmental Protection Division for a site in Georgia and increases at three Illinois sites due to refinement of the assumptions used in the cost method.

In July 2014, we reached a $77 million insurance settlement for environmental claims relating to potential contamination at our MGP sites in New Jersey and North Carolina. The terms of the settlement required the $77 million to be paid in two installments. We received $45 million in the third quarter of 2014 and this payment was primarily recorded as a reduction to our recoverable ERC regulatory asset. The remaining $32 million is due in the third quarter of 2015. We will file for approval with the New Jersey BPU to utilize the insurance proceeds related to the New Jersey sites to reduce the ERC expenditures that otherwise would have been recovered from our customers in future periods. As such, the settlement, once approved, is expected to reduce our recoverable ERC regulatory asset and have a favorable impact on the rates for our Elizabethtown Gas customers.

Bad Debt Rider Nicor Gas' bad debt rider provides for the recovery from, or refund to, customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and a benchmark, as determined by the Illinois Commission in February 2010. The over recovery is recorded as an increase to operating expenses on our Consolidated Statements of Income and a regulatory liability on our Consolidated Statements of Financial Position until refunded to customers. In the period refunded, operating expenses are reduced and the regulatory liability is reversed. The actual bad debt experience and resulting refunds are shown in the following table.

		Actual	Total	Amount refunded in		Amount to be refunded in	
In millions	**Benchmark**	**bad debt**	**refund**	**2013**	**2014**	**2015**	**2016**
2014	$63	$35	$28	$-	$-	$16	$12
2013	63	21	42	-	25	17	-
2012	63	23	40	24	16	-	-

Accumulated Removal Costs In accordance with regulatory treatment, our depreciation rates are comprised of two cost components - historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through straight-line depreciation expense, with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs are not a generally accepted component of depreciation, but meet the requirements of authoritative guidance related to regulated operations, we have reclassified them from accumulated depreciation to the accumulated removal cost regulatory liability in our Consolidated Statements of Financial Position. In the rate setting process, the liability for these accumulated removal costs is treated as a reduction to the net rate base upon which our regulated utilities have the opportunity to earn their allowed rate of return.

Regulatory Infrastructure Programs We have infrastructure improvement programs at several of our utilities. Descriptions of these are as follows.

Nicor Gas In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average of 4.0% of base rate revenues. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we may implement rates under the program effective in March 2015.

Atlanta Gas Light Our STRIDE program is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and the Integrated Vintage Plastic Replacement Program (i-VPR).

The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. The STRIDE program requires us to file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

A new $260 million, four-year STRIDE program was approved in December 2013, of which $214 million is for i-SRP related projects and $46 million is for i-CGP related projects. The program will be funded through a monthly rider surcharge per customer of $0.48 beginning in January 2015, which will increase to $0.96 beginning in January 2016 and to $1.43 beginning in January 2017. This surcharge will continue through 2025.

The purpose of the i-VPR program is to replace aging plastic pipe that was installed primarily in the 1960's to the early 1980's. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for replacement over the next 15 - 20 years as it reaches the end of its useful life. In 2013, the Georgia Commission approved the replacement of 756 miles of vintage plastic pipe over four years at an estimated cost of $275 million. Additional reporting requirements and monitoring by the staff of the Georgia Commission were also included in the stipulation, which authorized a phased-in approach to funding the program through a monthly rider surcharge of $0.48 per customer through December 2014. This will increase to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016, which will continue through 2025.

The orders for the STRIDE programs provide for recovery of all prudent costs incurred in the performance of the program. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the programs net of any cost savings from the programs. All such amounts will be recovered through a combination of straight-fixed-variable rates and a STRIDE revenue rider surcharge. The regulatory asset represents recoverable incurred costs related to the programs that will be collected in future rates charged to customers through the rate riders. The future expected costs to be recovered through rates related to allowed, but not incurred costs, are recognized in an unrecognized ratemaking amount that is not reflected within our Consolidated Statements of Financial Position. This allowed cost consists primarily of the equity return on the capital investment under the program.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the STRIDE programs over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Elizabethtown Gas In 2009, the New Jersey BPU approved the enhanced infrastructure program for Elizabethtown Gas, which was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. In May 2011, the New Jersey BPU approved Elizabethtown Gas' request to spend an additional $40 million under this program before the end of 2012. Costs associated with the investment in this program are recovered through periodic adjustments to base rates that are approved by the New Jersey BPU. In August 2013, the New Jersey BPU approved the recovery of investments under this program through a permanent adjustment to base rates.

Additionally, in August 2013, we received approval from the New Jersey BPU for an extension of the accelerated infrastructure replacement program, which allows for infrastructure investment of $115 million over four years, effective as of September 1, 2013. Carrying charges on the additional capital expenditures will be deferred at a WACC of 6.65%, of which 4.27% will be within an unrecognized ratemaking amounts and will be recognized in future periods when recovered through rates. Unlike the previous program, there will be no adjustment to base rates for the investments under the extended program until Elizabethtown Gas files its next rate case. We agreed to file a general rate case by September 2016.

In September 2013, Elizabethtown Gas filed for a Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program designed to improve our distribution system's resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas is investing $15 million in infrastructure and related facilities and communication planning over a one year period that began in January 2014. In July 2014, the New Jersey BPU approved a modified ENDURE plan that allows for Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program.

Virginia Natural Gas In 2012, the Virginia Commission approved SAVE, an accelerated infrastructure replacement program, which is expected to be completed over a five-year period. The program permits a maximum capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering program costs through a rate rider that was effective August 1, 2012. The second year performance rate update was approved by the Virginia Commission in July 2014 and became effective as of August 2014.

Energy Smart Plan In May 2014, the Illinois Commission approved Nicor Gas' Energy Smart Plan, which outlines energy efficiency program offerings and therm reduction goals with spending of $93 million over a three-year period that began in June 2014. Nicor Gas' first energy efficiency program ended in May 2014.

Investment Tax Credits Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our Consolidated Statements of Financial Position. These investment tax credits are being amortized over the estimated lives of the related properties as credits to income tax expense.

Regulatory Income Tax Liability For our regulated utilities, we measure deferred income tax assets and liabilities using enacted income tax rates. Thus, when the statutory income tax rate declines before a temporary difference has fully reversed, the deferred income tax liability must be reduced to reflect the newly enacted income tax rates. However, the amount of the reduction is transferred to our regulatory income tax liability, which we are amortizing over the lives of the related properties as the temporary differences reverse over approximately 30 years.

Other Regulatory Assets and Liabilities Our recoverable pension and retiree welfare benefit plan costs for our utilities other than Nicor Gas are expected to be recovered through base rates over the next 2 to 21 years, based on the remaining recovery periods as designated by the applicable state regulatory commissions. This category also includes recoverable seasonal rates, which reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. These amounts are fully recoverable through base rates within one year.

Note 4 - Fair Value Measurements

Retirement benefit plans assets

The assets of the AGL Resources Inc. Retirement Plan (AGL Plan), the Employees' Retirement Plan of NUI Corporation (NUI Plan), and the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) were allocated approximately 71% equity and 29% fixed income at December 31, 2014 and 74% equity and 26% fixed income at December 31, 2013 compared to our targets of 70% to 95% equity, 5% to 20% fixed income, and up to 10% cash for both periods. The plans' investment policies provide for some variation in these targets. The actual asset allocations of our retirement plans are presented in the following table by Level within the fair value hierarchy.

	December 31, 2014									
	Pension plans (1)					Welfare plans				
In millions	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**
Cash	**$4**	**$1**	**$-**	**$5**	**1%**	**$1**	**$-**	**$-**	**$1**	**1%**
Equity securities:										
U.S. large cap (2)	$95	$203	$-	$298	33%	$-	$51	$-	$51	57%
U.S. small cap (2)	76	24	-	100	11%	-	-	-	-	-%
International companies (3)	-	123	-	123	13%	-	16	-	16	18%
Emerging markets (4)	-	31	-	31	3%	-	-	-	-	-%
Total equity securities	**$171**	**$381**	**$-**	**$552**	**60%**	**$-**	**$67**	**$-**	**$67**	**75%**
Fixed income securities:										
Corporate bonds (5)	$-	$233	$-	$233	25%	$-	$22	$-	$22	24%
Other (or gov't/muni bonds)	-	33	-	33	4%	-	-	-	-	-%
Total fixed income securities	**$-**	**$266**	**$-**	**$266**	**29%**	**$-**	**$22**	**$-**	**$22**	**24%**
Other types of investments:										
Global hedged equity (6)	$-	$-	$29	$29	3%	$-	$-	$-	$-	-%
Absolute return (7)	-	-	42	42	5%	-	-	-	-	-%
Private capital (8)	-	-	20	20	2%	-	-	-	-	-%
Total other investments	**$-**	**$-**	**$91**	**$91**	**10%**	**$-**	**$-**	**$-**	**$-**	**-%**
Total assets at fair value	**$175**	**$648**	**$91**	**$914**	**100%**	**$1**	**$89**	**$-**	**$90**	**100%**
% of fair value hierarchy	19%	71%	10%	100%		1%	99%	-%	100%	

	December 31, 2013									
	Pension plans (1)					Welfare plans				
In millions	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**
Cash	**$3**	**$1**	**$-**	**$4**	**-%**	**$1**	**$-**	**$-**	**$1**	**1%**
Equity securities:										
U.S. large cap (2)	$93	$205	$-	$298	33%	$-	$52	$-	$52	62%
U.S. small cap (2)	72	29	-	101	11%	-	-	-	-	-%
International companies (3)	-	139	-	139	15%	-	14	-	14	17%
Emerging markets (4)	-	34	-	34	4%	-	-	-	-	-%
Total equity securities	**$165**	**$407**	**$-**	**$572**	**63%**	**$-**	**$66**	**$-**	**$66**	**79%**
Fixed income securities:										
Corporate bonds (5)	$-	$207	$-	$207	23%	$-	$17	$-	$17	20%
Other (or gov't/muni bonds)	-	29	-	29	3%	-	-	-	-	-%
Total fixed income securities	**$-**	**$236**	**$-**	**$236**	**26%**	**$-**	**$17**	**$-**	**$17**	**20%**
Other types of investments:										
Global hedged equity (6)	$-	$-	$43	$43	5%	$-	$-	$-	$-	-%
Absolute return (7)	-	-	39	39	4%	-	-	-	-	-%
Private capital (8)	-	-	22	22	2%	-	-	-	-	-%
Total other investments	**$-**	**$-**	**$104**	**$104**	**11%**	**$-**	**$-**	**$-**	**$-**	**-%**
Total assets at fair value	**$168**	**$644**	**$104**	**$916**	**100%**	**$1**	**$83**	**$-**	**$84**	**100%**
% of fair value hierarchy	19%	70%	11%	100%		1%	99%	-%	100%	

(1) Includes $9 million at December 31, 2014 and December 31, 2013 of medical benefit (health and welfare) component for 401h accounts to fund a portion of the other retirement benefits.
(2) Includes funds that invest primarily in U.S. common stocks.
(3) Includes funds that invest primarily in foreign equity and equity-related securities.
(4) Includes funds that invest primarily in common stocks of emerging markets.
(5) Includes funds that invest primarily in investment grade debt and fixed income securities.
(6) Includes funds that invest in limited / general partnerships, managed accounts, and other investment entities issued by non-traditional firms or "hedge funds."
(7) Includes funds that invest primarily in investment vehicles and commodity pools as a "fund of funds."

(8) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly / indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real estate mezzanine loans.

The following is a reconciliation of our retirement plan assets in Level 3 of the fair value hierarchy.

	Fair value measurements using significant unobservable inputs - Level 3 (1)			
In millions	**Global hedged equity**	**Absolute return**	**Private capital**	**Total**
Balance at December 31, 2012	$38	$36	$23	$97
Actual return on plan assets	5	3	4	12
Sales	-	-	(5)	(5)
Balance at December 31, 2013	$43	$39	$22	$104
Actual return on plan assets	1	3	2	6
Sales	(15)	-	(4)	(19)
Balance at December 31, 2014	$29	$42	$20	$91

(1) There were no transfers out of Level 3, or between Level 1 and Level 2 for any of the periods presented.

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were carried at fair value on a recurring basis in our Consolidated Statements of Financial Position as of December 31.

	2014		2013	
In millions	**Assets** (1)	**Liabilities**	**Assets** (1)	**Liabilities**
Natural gas derivatives				
Quoted prices in active markets (Level 1)	$58	$(80)	$6	$(79)
Significant other observable inputs (Level 2)	174	(94)	67	(79)
Netting of cash collateral	52	81	43	78
Total carrying value (2) (3)	$284	$(93)	$116	$(80)

(1) Balances of $3 million at December 31, 2014 and 2013 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.
(2) There were no significant unobservable inputs (Level 3) for any of the dates presented.
(3) There were no significant transfers between Level 1, Level 2, or Level 3 for any of the dates presented.

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which are recorded at their acquisition-date fair value. We amortize the fair value adjustment of Nicor Gas' first mortgage bonds over the lives of the bonds. The following table presents the carrying amount and fair value of our long-term debt as of December 31.

In millions	**2014**	**2013**
Long-term debt carrying amount	$3,802	$3,813
Long-term debt fair value (1)	4,231	3,956

(1) Fair value determined using Level 2 inputs.

Note 5 - Derivative Instruments

Our risk management activities are monitored by our Risk Management Committee, which consists of members of senior management and is charged with reviewing our risk management activities and enforcing policies. Our use of derivative instruments, including physical transactions, is limited to predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following types of derivative instruments and energy-related contracts to manage natural gas price, interest rate, weather, automobile fuel price and foreign currency risks when deemed appropriate:

- forward, futures and options contracts;
- financial swaps;
- treasury locks;
- weather derivative contracts;
- storage and transportation capacity contracts; and
- foreign currency forward contracts

Certain of our derivative instruments contain credit-risk-related or other contingent features that could require us to post collateral in the normal course of business when our financial instruments are in net liability positions. As of December 31, 2014 and 2013, for agreements with such features, derivative instruments with liability fair values totaled $93 million and $80 million, respectively, for which we had posted no collateral to our counterparties. The maximum collateral that could be required with these features is $14 million. For more information, see "Energy Marketing Receivables and Payables" in Note 2, which also have credit risk-related contingent features. Our derivative instrument activities are included within operating cash flows as an increase (decrease) to net income of $(155) million, $66 million and $72 million for the periods ended December 31, 2014, 2013 and 2012, respectively.

The following table summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

Accounting Treatment	Recognition and Measurement: Statements of Financial Position	Recognition and Measurement: Income Statements
Cash flow hedge	Derivative carried at fair value	Ineffective portion of the gain or loss realized and unrealized on the derivative instrument is recognized in earnings
	Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated OCI (loss)	Effective portion of the gain or loss realized and unrealized on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the hedged transaction affects earnings
Fair value hedge	Derivative carried at fair value	Gains or losses realized and unrealized on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings
	Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	
Not designated as hedges	Derivative carried at fair value	Gains or losses realized and unrealized on the derivative instrument are recognized in earnings
	Distribution operations' gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in cost of goods sold	Gains or losses realized and unrealized on these derivative instruments are ultimately included in billings to customers and are recognized in cost of goods sold in the same period as the related revenues

Quantitative Disclosures Related to Derivative Instruments

As of the dates presented, our derivative instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. As of December 31, we had a net long natural gas contracts position outstanding in the following quantities:

In Bcf (1)	**2014** (2)	**2013**
Cash flow hedges	9	6
Not designated as hedges	75	183
Total volumes	84	189
Short position – cash flow hedges	(4)	(6)
Short position – not designated as hedges	(2,828)	(2,616)
Long position – cash flow hedges	16	12
Long position – not designated as hedges	2,900	2,799
Net long position	84	189

(1) Volumes related to Nicor Gas exclude variable-priced contracts, which are carried at fair value, but whose fair values are not directly impacted by changes in commodity prices.
(2) Approximately 100% of these contracts have durations of two years or less and less than 1% expire between two and five years.

Derivative Instruments in our Consolidated Statements of Financial Position

In accordance with regulatory requirements, gains and losses on derivative instruments used to hedge natural gas purchases for customer use at distribution operations are reflected in accrued natural gas costs within our Consolidated Statements of Financial Position until billed to customers. The following amounts deferred as a regulatory asset or liability on our Consolidated Statements of Financial Position represent the net realized gains (losses) related to these natural gas cost hedges for the years ended December 31.

In millions	2014	2013
Nicor Gas	$10	$4
Elizabethtown Gas	2	(6)

The following table presents the fair values and Consolidated Statements of Financial Position classifications of our derivative instruments as of December 31:

		2014		2013	
In millions	**Classification**	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Designated as cash flow or fair value hedges					
Natural gas contracts	Current	$6	$(11)	$3	$(1)
Natural gas contracts	Long-term	-	(1)	-	-
Total designated as cash flow or fair value hedges		$6	$(12)	$3	$(1)
Not designated as hedges					
Natural gas contracts	Current	$1,061	$(1,020)	$691	$(761)
Natural gas contracts	Long-term	145	(119)	206	(220)
Total not designated as hedges		$1,206	$(1,139)	$897	$(981)
Gross amount of recognized assets and liabilities (1) (2)		1,212	(1,151)	900	(982)
Gross amounts offset in our Consolidated Statements of Financial Position (2)		(925)	1,058	(781)	902
Net amounts of assets and liabilities presented in our Consolidated Statements of Financial Position (3)		$287	$(93)	$119	$(80)

(1) The gross amounts of recognized assets and liabilities are netted within our Consolidated Statements of Financial Position to the extent that we have netting arrangements with the counterparties.

(2) As required by the authoritative guidance related to derivatives and hedging, the gross amounts of recognized assets and liabilities above do not include cash collateral held on deposit in broker margin accounts of $133 million as of December 31, 2014 and $121 million as of December 31, 2013. Cash collateral is included in the "Gross amounts offset in our Consolidated Statements of Financial Position" line of this table.

(3) At December 31, 2014 and 2013, we held letters of credit from counterparties that would offset, under master netting arrangements, an insignificant portion of these assets.

Derivative Instruments on the Consolidated Statements of Income

The following table presents the impacts of our derivative instruments in our Consolidated Statements of Income for the years ended December 31.

In millions	2014	2013	2012
Designated as cash flow or fair value hedges			
Natural gas contracts – net gain (loss) reclassified from OCI into cost of goods sold	$4	$(1)	$(5)
Natural gas contracts – net gain reclassified from OCI into operation and maintenance expense	1	-	-
Interest rate swaps – net loss reclassified from OCI into interest expense	-	(3)	(4)
Income tax (expense)/benefit	(2)	1	3
Total designated as cash flow or fair value hedges, net of tax	$3	$(3)	$(6)
Not designated as hedges (1)			
Natural gas contracts - net gain (loss) recorded in operating revenues	$149	$(90)	$34
Natural gas contracts - net gain (loss) recorded in cost of goods sold (2)	(7)	2	(4)
Income tax (expense)/benefit	(54)	34	(11)
Total not designated as hedges, net of tax	$88	$(54)	$19
Total gains (losses) on derivative instruments, net of tax	$91	$(57)	$13

(1) Associated with the fair value of derivative instruments held at December 31, 2014, 2013 and 2012.

(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $7 million, $5 million and $14 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Any amounts recognized in operating income related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur were immaterial for the years ended December 31, 2014, 2013 and 2012. Our expected gains to be reclassified from OCI into cost of goods sold, operation and maintenance expense, interest expense and operating revenues and recognized in our Consolidated Statements of Income over the next 12 months are $7 million. These deferred gains are related to natural gas derivative contracts associated with retail operations' and Nicor Gas' system use.

The expected gains are based upon the fair values of these financial instruments at December 31, 2014. The effective portion of gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in OCI during the periods is presented on our Consolidated Statements of Income. See Note 9 for these amounts.

Note 6 - Employee Benefit Plans

Investment Policies, Strategies and Oversight of Plans

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of our defined benefit retirement plans. Further, we have an Investment Policy (the Policy) for our pension and welfare benefit plans whose goal is to preserve these plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the plans' assets are managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification.

In developing our allocation policy for the pension and welfare plan assets we examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, we evaluated the risk and return tradeoffs of alternative asset classes and asset mixes given long-term historical relationships as well as prospective capital market returns. We also conducted an asset-liability study to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. We developed our asset mix guidelines by incorporating the results of these analyses with an assessment of our risk posture, and taking into account industry practices. We periodically evaluate our investment strategy to ensure that plan assets are sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, we may make changes to our targeted asset allocations and investment strategy.

Our investment strategy is designed to meet the following objectives:

- Generate investment returns that, in combination with our funding contributions, provide adequate funding to meet all current and future benefit obligations of the plans.
- Provide investment results that meet or exceed the assumed long-term rate of return, while maintaining the funded status of the plans at acceptable levels.
- Improve funded status over time.
- Decrease contribution and expense volatility as funded status improves.

To achieve these investment objectives, our investment strategy is divided into two primary portfolios of return seeking and liability hedging assets. Return seeking assets are intended to provide investment returns in excess of liability growth and reduce deficits in the funded status of the plans, while liability hedging assets are intended to reflect the sensitivity of the liabilities to changes in discount rates.

See Note 4 for a detailed listing of the investment types, amounts and percentages allocated to the plans. We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income securities (corporate and government obligations), cash and cash equivalents and other suitable investments.

Equity market performance and corporate bond rates have a significant effect on our reported funded status. Changes in the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) are mainly driven by the assumed discount rate. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is used by the AGL Plan to determine the expected return on the plan assets component of net annual pension cost. The MRVPA is a calculated value. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology.

Pension Benefits

We sponsor the AGL Plan, which is a tax-qualified defined benefit retirement plan for our eligible employees. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant, including information related to the participant's earnings history, years of service and age. In 2012, we also sponsored two other tax-qualified defined benefit retirement plans for our eligible employees, a Nicor plan and a NUI plan. Effective as of December 31, 2012, the NUI plan and the Nicor plan were merged into the AGL Plan. The participants of the former Nicor and NUI plans are now being offered their benefits, as described below, through the AGL Plan.

We generally calculate the benefits under the AGL Plan based on age, years of service and pay. The benefit formula for the AGL Plan is currently a career average earnings formula. Participants who were employees as of July 1, 2000 and who were at least 50 years of age as of that date earned benefits until December 31, 2010 under a final average pay formula. Participants who were employed as of July 1, 2000, but did not satisfy the age requirement to continue under the final average earnings formula, transitioned to the career average earnings formula on July 1, 2000.

Effective January 1, 2012, the AGL Plan was frozen with respect to participation for non-union employees hired on or after that date. Effective January 1, 2013, the AGL Plan was frozen with respect to participation for union employees hired on or after that date. Such employees are entitled to employer provided benefits under their defined contribution plan that exceed defined contribution benefits for employees who participate in the defined benefit plan.

Participants in the former Nicor plan receive noncontributory defined pension benefits. These benefits cover substantially all employees of Nicor Gas and its affiliates that adopted the Nicor plan hired prior to 1998. Pension benefits are based on years of service and the highest average annual salary for management employees and job level for collectively bargained employees (referred to as pension bands). The benefit obligation related to collectively bargained benefits reflects the most recent collective bargained agreement terms with regards to the benefit increases.

Participants in the former NUI plan included substantially all of NUI Corporation's employees who were employed on or before December 31, 2005. Florida City Gas union employees, who until February 2008 participated in a union-sponsored multiemployer plan, became eligible to participate in the AGL Plan in February 2008. The AGL Plan provides pension benefits to NUI participants based on years of credited service and final average compensation as of the plan freeze date. Effective December 31, 2005, participation and benefit accrual under the NUI Plan were frozen. As of January 1, 2006, former participants in that plan became eligible to participate in the AGL Plan.

Welfare Benefits

Until December 31, 2012, we sponsored two defined benefit retiree health care plans for our eligible employees – the AGL Welfare Plan and the Nicor Welfare Benefit Plan (Nicor Welfare Plan). Eligibility for these benefits is based on age and years of service. Effective December 31, 2012, the Nicor Welfare Plan was terminated and as of January 1, 2013, all participants under that plan became eligible to participate in the AGL Welfare Plan. This change in plan participation eligibility did not affect the benefit terms. The Nicor Welfare Plan benefits described below are now being offered to such participants under the AGL Welfare Plan. Effective March 18, 2014, the Nicor Welfare Plan was closed to participation for all Nicor employees hired on or after that date.

The AGL Welfare Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach the plan's retirement age while working for us. In addition, the AGL Welfare Plan provides life insurance for all employees if they have ten years of service at retirement. Effective March 18, 2014, the life insurance coverage is not available to new employees hired on or after that date. The state regulatory commissions have approved phase-in plans that defer a portion of the related benefits expense for future recovery. The AGL Welfare Plan terms include a limit on the employer share of costs at limits based on the coverage tier, plan elected and salary level of the employee at retirement.

Medicare eligible retirees covered by the AGL Welfare Plan, including all of those at least age 65, receive benefits through our contribution to a retiree health reimbursement arrangement account. Additionally, on the pre-65 medical coverage of the AGL Welfare Plan, our expected cost is determined by a retiree premium schedule based on salary level and years of service. Due to the cost limits, there is no impact on our periodic benefit cost or on our accumulated projected benefit obligation for a change in the assumed healthcare cost trend rate for this portion of the plan.

The plan provisions that are applicable to prior participants in the Nicor Welfare Plan include health care and life insurance benefits to eligible retired employees and include a limit on the employer share of cost for employees hired after 1982.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 provides for a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Prescription drug coverage for the Nicor Gas Medicare-eligible population changed effective January 1, 2013 from an employer-sponsored prescription drug plan with the Retiree Drug Subsidy to an Employer Group Waiver Plan (EGWP). The EGWP replaces the employer sponsored prescription drug plan.

We also have a separate unfunded supplemental retirement health care plan that provides health care and life insurance benefits to employees of discontinued businesses. This plan is noncontributory with defined benefits. Net plan expenses were immaterial in 2014 and 2013. The APBO associated with this plan was $2 million at December 31, 2014 and $2 million at December 31, 2013.

Assumptions

We considered a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We based our discount rates separately for each plan on an above-mean yield curve provided by our actuaries that is derived from a portfolio of high quality (rated AA or better) corporate bonds with a yield higher than the regression mean curve and the equivalent annuity cash flows.

The components of our pension and welfare costs are set forth in the following table.

Dollars in millions	Pension plans 2014	2013	2012	Welfare plans 2014	2013	2012
Service cost	$24	$29	$28	$2	$3	$4
Interest cost	47	43	44	15	14	16
Expected return on plan assets	(65)	(62)	(64)	(7)	(6)	(5)
Net amortization of prior service cost	(2)	(2)	(2)	(3)	(5)	(3)
Recognized actuarial loss	22	35	34	6	8	9
Net periodic benefit cost	$26	$43	$40	$13	$14	$21
Assumptions used to determine benefit costs						
Discount rate (1)	5.0%	4.2%	4.6%	4.7%	4.0%	4.5%
Expected return on plan assets (1)	7.8%	7.8%	8.4%	7.8%	7.8%	8.5%
Rate of compensation increase (1)	3.7%	3.7%	3.7%	3.7%	3.8%	3.8%
Pension band increase (2)	2.0%	2.0%	2.0%	n/a	n/a	n/a

(1) Rates are presented on a weighted average basis.
(2) Only applicable to the Nicor Gas union employees. The pension bands for the former Nicor Plan have been updated to reflect the new negotiated rates for 2015 and 2016, of 2.0% and 0%, respectively, as indicated in the union agreement dated March 2014.

The following tables present details about our pension and welfare plans.

Dollars in millions	Pension plans 2014	2013	Welfare plans 2014	2013
Change in plan assets				
Fair value of plan assets, January 1,	$907	$837	$93	$77
Actual return on plan assets	68	134	5	16
Employee contributions	-	-	2	3
Employer contributions	1	1	17	19
Benefits paid	(70)	(65)	(19)	(23)
Medicare Part D reimbursements	-	-	1	1
Fair value of plan assets, December 31,	$906	$907	$99	$93
Change in benefit obligation				
Benefit obligation, January 1,	$960	$1,046	$326	$354
Service cost	24	29	2	3
Interest cost	47	43	15	14
Actuarial loss (gain)	137	(93)	8	(26)
Medicare Part D reimbursements	-	-	1	1
Benefits paid	(70)	(65)	(19)	(23)
Employee contributions	-	-	1	3
Benefit obligation, December 31,	$1,098	$960	$334	$326
Funded status at end of year	$(192)	$(53)	$(235)	$(233)
Amounts recognized in the Consolidated Statements of Financial Position consist of				
Long-term asset (2)	$97	$117	$-	$-
Current liability	(2)	(2)	-	-
Long-term liability	(287)	(168)	(235)	(233)
Net liability at December 31,	$(192)	$(53)	$(235)	$(233)
Accumulated benefit obligation (1)	$1,027	$902	n/a	n/a
Assumptions used to determine benefit obligations				
Discount rate	4.2%	5.0%	4.0%	4.7%
Rate of compensation increase	3.7%	3.7%	3.7%	3.7%
Pension band increase (3)	2.0%	2.0%	n/a	n/a

(1) APBO differs from the projected benefit obligation in that APBO excludes the effect of salary and wage increases.
(2) As a result of historically having multiple plans, a portion of our obligation is in an asset position.
(3) Only applicable to the Nicor Gas union employees.

A portion of the net benefit cost or credit related to these plans has been capitalized as a cost of constructing gas distribution facilities and the remainder is included in operation and maintenance expense.

Assumptions used to determine the health care benefit cost for the AGL Welfare Plan were as follows:

	2014	2013
Health care cost trend rate assumed for next year	8.1%	8.4%
Ultimate rate to which the cost trend rate is assumed to decline	4.5%	4.5%
Year that reaches ultimate trend rate	2030	2030

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates for the AGL Welfare Plan would have the following effects on our benefit obligation and there was no effect on our service and interest cost.

In millions	Effect on benefit obligation
1% Health care cost trend rate increase	$15
1% Health care cost trend rate decrease	(13)

As a result of a cap on expected cost for the AGL Welfare Plan, a one percentage point increase or decrease in the assumed health care trend does not materially affect the Plan's periodic benefit cost or accumulated benefit obligation.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in net regulatory assets and accumulated OCI as of December 31, 2014 and 2013:

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
December 31, 2014:						
Prior service credit	$-	$(18)	$(6)	$-	$(6)	$(18)
Net loss	76	57	307	36	383	93
Total	$76	$39	$301	$36	$377	$75
December 31, 2013:						
Prior service credit	$-	$(20)	$(9)	$-	$(9)	$(20)
Net loss	61	60	210	30	271	90
Total	$61	$40	$201	$30	$262	$70

The 2015 estimated amortizations out of regulatory assets or accumulated OCI for these plans are set forth in the following table.

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
Amortization of prior service credit	$-	$(3)	$(2)	$-	$(2)	$(3)
Amortization of net loss	9	3	20	2	29	5

We recorded regulatory assets for anticipated future cost recoveries of $122 million and $108 million as of December 31, 2014 and 2013, respectively.

The following table presents the gross benefit payments expected for the years ended December 31, 2015 through 2024 for our pension and welfare plans. There will be benefit payments under these plans beyond 2024.

In millions	Pension plans	Welfare plans
2015	$61	$19
2016	64	20
2017	67	20
2018	70	21
2019	72	22
2020-2024	374	115

Contributions

Our employees generally do not contribute to our pension and welfare plans; however, Nicor Gas and pre-65 AGL retirees make nominal contributions to their health care plan. We fund the qualified pension plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. As required by The Pension Protection Act of 2006 (the Act), we calculate the minimum amount of funding using the traditional unit credit cost method.

The Act contained new funding requirements for single-employer defined benefit pension plans and established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. In 2014 and 2013, we had no required contributions to the merged AGL Plan.

Employee Savings Plan Benefits

We sponsor defined contribution retirement benefit plans that allow eligible participants to make contributions to their accounts up to specified limits. Under these plans, our matching contributions to participant accounts were $17 million in 2014, $14 million in 2013 and $12 million in 2012.

Note 7 – Stock-Based Compensation

General

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provide for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards and other stock-based awards to officers and key employees. Under the Omnibus Performance Incentive Plan, as of December 31, 2014, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 587,292 shares. Under the Long-Term Incentive Plan (1999) as of December 31, 2014, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 436,400 shares. The maximum number of shares available for future issuance under the Omnibus Performance Incentive Plan is 3,962,335 shares, which includes 1,551,040 shares previously available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, pursuant to NYSE rules. No further grants will be made from the Long-Term Incentive Plan (1999) except for reload options that may be granted pursuant to the terms of certain outstanding options.

Accounting Treatment and Compensation Expense

We measure and recognize stock-based compensation expense for our stock-based awards over the requisite service period in our financial statements based on the estimated fair value at the date of grant for our stock-based awards using the modified prospective method. These stock awards include:

- stock options;
- stock and restricted stock awards; and
- performance units (restricted stock units, performance share units and performance cash units).

Performance-based stock awards and performance units contain market and performance conditions. Stock options, restricted stock awards and performance units also contain a service condition.

We estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates. The authoritative guidance requires excess tax benefits to be reported as a financing cash inflow. The difference between the proceeds from the exercise of our stock-based awards and the par value of the stock is recorded within additional paid-in capital.

We have granted incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. Fair market value is defined under the terms of the applicable plans as the closing price per share of AGL Resources common stock for the trading day immediately preceding the grant date, as reported in *The Wall Street Journal*. Stock options generally have a three-year vesting period.

The following table provides additional information related to our cash and stock-based compensation awards.

In millions	**2014**	**2013**	**2012**
Compensation costs (1)	$24	$22	$9
Income tax benefits (1)	1	1	1
Excess tax benefits (2)	-	-	1

(1) Recorded in our Consolidated Statements of Income.
(2) Recorded in our Consolidated Statements of Financial Position.

Incentive and Nonqualified Stock Options

The stock options we granted generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant.

As of December 31, 2014 and 2013, we had no unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2014 and 2013 were $9 million and $21 million, respectively, and the income tax benefit from stock option exercises was immaterial for both years. The following tables summarize activity related to stock options for key employees and non-employee directors. As used in the table, intrinsic value for options means the difference between the current market value and the grant price.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding - December 31, 2011	1,823,154	$35.61		
Granted	-	-		
Exercised	(234,844)	32.07		
Forfeited	(59,720)	37.34		
Outstanding - December 31, 2012(1)	1,528,590	$36.09		
Granted	-	-		
Exercised	(617,358)	35.37		
Forfeited	(12,500)	38.36		
Outstanding - December 31, 2013 (1)	898,732	$36.55	3.0	$10
Granted	-	-	-	
Exercised	(267,182)	36.84	1.7	
Forfeited	(4,000)	39.71	2.7	
Outstanding - December 31, 2014 (1) (2)	627,550	$36.41	2.2	$11

(1) All options outstanding at December 31, 2014, 2013 and 2012 were exercisable.

(2) The range of exercise prices for the options outstanding at December 31, 2014 was $31.09 to $43.54.

We measure compensation cost related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. There were no options granted in 2014, 2013 and 2012. We use shares purchased under our 2006 share repurchase program to satisfy exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

In general, a performance unit is an award of the right to receive (i) an equal number of shares of our common stock, which we refer to as a restricted stock unit or (ii) cash, subject to the achievement of certain pre-established performance criteria, which we refer to as a performance cash unit. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. The compensation cost of restricted stock unit awards is equal to the grant date fair value of the awards, recognized over the requisite service period, determined according to the authoritative guidance related to stock compensation. The compensation cost of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, recognized over the requisite service period. No other assumptions are used to value these awards.

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2014, we granted 44,272 restricted stock units (including dividends) to certain employees, all of which were outstanding as of December 31, 2014. These restricted stock units had a performance measurement period that ended December 31, 2014. The performance measure, which related to earnings before interest, income tax, depreciation and amortization, was met. As such, the related restricted stock awards will occur in 2015 and are subject to a three year service condition.

Performance Share Unit Awards A performance share unit award represents the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. In 2012, 2013 and 2014, we granted performance share unit awards to certain officers. These awards have a performance measure that relates to the company's relative total shareholder return relative to a group of peer companies. The recorded liability and maximum potential liability related to the 2014, 2013 and 2012 grants are as follows:

In millions	Measurement period end date	Fair value accrued at December 31, 2014	Maximum aggregate payout
Granted in 2012	December 31, 2014 (1)	$8	$20
Granted in 2013	December 31, 2015	7	21
Granted in 2014	December 31, 2016	4	24

(1) The actual liability is $8 million, and the maximum amount that could have been paid was $20 million.

Stock and Restricted Stock Awards

The compensation cost of both stock awards and restricted stock awards is equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions are used to value the awards. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Prior to vesting, restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment.

Stock Awards - ***Non-Employee Directors*** Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and non-forfeitable as of the date of grant. During 2014, we issued 21,903 shares with a weighted average fair value of $52.97 to our non-employee directors.

Restricted Stock Awards - Employees The following table summarizes the restricted stock awards activity for our employees during the last three years.

	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding - December 31, 2011 (1)	477,354		$34.40
Issued	268,840		40.08
Forfeited	(28,829)		39.07
Vested	(214,274)		36.45
Outstanding - December 31, 2012 (1)	503,091		$39.44
Issued	175,935		42.41
Forfeited	(33,352)		40.64
Vested	(204,421)		38.71
Outstanding - December 31, 2013 (1)	441,253	1.8	$40.82
Issued	262,235	4.4	47.03
Forfeited	(14,895)	2.4	43.41
Vested	(225,683)	-	42.31
Outstanding - December 31, 2014 (1)	462,910	1.8	$43.54

(1) Subject to restriction.

Employee Stock Purchase Plan (ESPP)

We have a nonqualified, broad based ESPP for all eligible employees. As of December 31, 2014, there were 422,564 shares available for future issuance under this plan. Employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value, and we record an expense for the 15% purchase price discount. Employee ESPP contributions may not exceed $25,000 per employee during any calendar year.

	2014	2013	2012
Shares purchased on the open market	100,199	97,734	103,589
Average per-share purchase price	$51.60	$42.96	$38.96
Total purchase price discount	$739,598	$628,358	$591,855

Note 8 - Debt and Credit Facilities

Our financing activities, including long-term and short-term debt, are subject to customary approval or review by state and federal regulatory bodies. Our wholly owned subsidiary, AGL Capital, was established to provide for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities and other financing arrangements. We fully and unconditionally guarantee all debt issued by AGL Capital. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize AGL Capital for its financing needs. The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included in our Consolidated Statements of Financial Position.

		December 31, 2014		December 31, 2013	
Dollars in millions	Year(s) due	Weighted average interest rate (1)	Outstanding	Weighted average interest rate (1)	Outstanding
Short-term debt					
Commercial paper - AGL Capital (2)	2015	0.3%	$590	0.4%	$857
Commercial paper - Nicor Gas (2)	2015	0.2	585	0.3	314
Total short-term debt		0.3%	$1,175	0.4%	$1,171
Current portion of long-term debt	2015	5.0%	$200	-%	$-
Long-term debt - excluding current portion					
Senior notes	2016-2043	5.0%	$2,625	5.0%	$2,825
First mortgage bonds	2016-2038	5.6	500	5.6	500
Gas facility revenue bonds	2022-2033	0.9	200	1.0	200
Medium-term notes	2017-2027	7.8	181	7.8	181
Total principal long-term debt		4.9%	$3,506	4.9%	$3,706
Fair value adjustment of long-term debt (3)	2016-2038	n/a	80	n/a	91
Unamortized debt premium, net	n/a	n/a	16	n/a	16
Total non-principal long-term debt		n/a	96	n/a	107
Total long-term debt			$3,602		$3,813
Total debt			$4,977		$4,984

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the 12 months ended December 31, 2014 and 2013.
(2) As of December 31, 2014, the effective interest rates on our commercial paper borrowings were 0.5% for AGL Capital and 0.4% for Nicor Gas.
(3) See Note 4 for additional information on our fair value measurements.

Short-term Debt

Our short-term debt at December 31, 2014 and 2013 was comprised of borrowings under our commercial paper programs.

Commercial Paper Programs We maintain commercial paper programs at AGL Capital and at Nicor Gas that consist of short-term, unsecured promissory notes used in conjunction with cash from operations to fund our seasonal working capital requirements. Working capital needs fluctuate during the year and are highest during the injection period in advance of the Heating Season. The Nicor Gas commercial paper program supports working capital needs at Nicor Gas, while all of our other subsidiaries and SouthStar participate in the AGL Capital commercial paper program. During 2014, our commercial paper maturities ranged from 1 to 108 days, and at December 31, 2014, remaining terms to maturity ranged from 2 to 70 days. During 2014, total borrowings and repayments netted to a borrowing of $4 million. For commercial paper issuances with original maturities over three months, borrowings and repayments were $50 million and $195 million, respectively. During 2014, we utilized a portion of the approximately $225 million in proceeds and distributions from the sale of Tropical Shipping to reduce our commercial paper borrowings.

Credit Facilities At December 31, 2014 and 2013, there were no outstanding borrowings under either the AGL Capital or Nicor Gas credit facilities. In 2013, the AGL Credit Facility and Nicor Gas Credit Facility maturity dates were extended to November 10, 2017 and December 15, 2017, respectively. The terms, conditions and pricing under the agreements remain unchanged.

Current Portion of Long-term Debt The current portion of our long-term debt at December 31, 2014 is composed of the portion of our long-term debt due within the next 12 months.

Long-term Debt

Our long-term debt at December 31, 2014 and 2013 consisted of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1, 1989; senior notes; first mortgage bonds; and gas facility revenue bonds. Some of these issuances were completed in the private placement market. In determining that those specific bonds qualify for exemption from registration under Section 4(2) of the Securities Act of 1933, we relied on the facts that the bonds were offered only to a limited number of large institutional investors and each institutional investor that purchased the bonds represented that it was purchasing the bonds for its own account and not with a view to distribute them. We fully and unconditionally guarantee all of our senior notes and gas facility revenue bonds. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds.

The majority of our long-term debt matures after fiscal year 2019. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	Amount (in millions)
2015	$200
2016	545
2017	22
2018	155
2019	350
Thereafter	2,434
Total	$3,706

Senior Notes There were no senior note issuances in 2014; however, during the fourth quarter of 2014, $120 million of senior notes that were issued to help fund the Nicor merger converted from a 1.9% fixed rate to a LIBOR-based floating rate. In 2013, we issued $500 million in 30-year senior notes with a fixed interest rate of 4.4%. The net proceeds were used to repay a portion of AGL Capital's commercial paper.

On January 23, 2015, we executed $800 million in notional value of 10 year and 30 year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated issuances of senior notes during 2015 and 2016. These debt issuances will be used to reduce our commercial paper for the amount that was borrowed to repay our senior notes that matured in January 2015 and to fund upcoming debt maturities as well as capital expenditures associated with increased utility investment and construction of our new pipeline projects. We have designated the forward-starting interest rate swaps, which will be settled on the debt issuance dates, as cash flow hedges.

First Mortgage Bonds We acquired the first mortgage bonds of Nicor Gas, which were issued through the public and private placement markets, as a result of the 2011 merger.

Gas Facility Revenue Bonds We are party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which a series of gas facility revenue bonds has been issued. These revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance are then loaned to us.

During 2013, we refinanced $200 million of our outstanding tax-exempt gas facility revenue bonds, which involved a combination of the issuance of $60 million of refunding bonds to, and the purchase of $140 million of existing bonds by, a syndicate of banks. We had no cash receipts or payments in connection with the refinancing. The letters of credit providing credit support for the outstanding revenue bonds along with other related agreements were terminated as a result of the refinancing.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month; however, our goal is to maintain these ratios at levels between 50% and 60%. These ratios, as calculated in accordance with the debt covenants, include standby letters of credit and surety bonds and exclude accumulated OCI items related to non-cash pension adjustments, welfare benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios as of December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2014	2013	2014	2013
Debt-to-capitalization ratio	55%	57%	62%	55%

The credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Default Provisions

Our credit facilities and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. The most important default events include the following:

- a maximum leverage ratio
- insolvency events and/or nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We have no triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other triggering events. We were in compliance with all existing debt provisions and covenants, both financial and non-financial, as of December 31, 2014 and 2013.

Note 9 - Equity

Treasury Shares

Our Board of Directors authorized us to purchase up to 8 million treasury shares through our repurchase plan, which expired on January 31, 2011. This plan was used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this plan were made in the open market or in private transactions at times and in amounts that we deemed appropriate. We held the purchased shares as treasury shares and accounted for them using the cost method. We purchased no treasury shares in 2014 or 2013.

Preferred Securities

At December 31, 2014 and 2013, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Dividends

Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors.

Additionally, we derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. As with most other companies, the payment of dividends is restricted by laws in the states where we conduct business. In certain cases, our ability to pay dividends to our common shareholders is limited by (i) our ability to pay our debts as they become due in the usual course of business and satisfy our obligations under certain financing agreements, including our debt-to-capitalization covenant, (ii) our ability to maintain total assets below total liabilities, and (iii) our ability to satisfy our obligations to any preferred shareholders.

Accumulated Other Comprehensive Loss

Our share of comprehensive income includes net income plus OCI (loss), which includes changes in fair value of certain derivatives designated as cash flow hedges, certain changes in pension and welfare benefit plans and reclassifications for amounts included in net income less net income, and OCI attributable to the noncontrolling interest. For more information on our derivative instruments, see Note 5. For more information on our pensions and retirement benefit obligations, see Note 6. Our OCI (loss) amounts are aggregated within accumulated other comprehensive loss on our Consolidated Statement of Financial Position. The following table provides changes in the components of our accumulated other comprehensive loss balances net of the related income tax effects.

In millions (1)	Cash flow hedges	Retirement benefit plans	Total
Balance as of December 31, 2011	$(7)	$(210)	$(217)
Other comprehensive income (loss)	4	(5)	(1)
Balance as of December 31, 2012	(3)	(215)	(218)
Other comprehensive income, before reclassifications	1	66	67
Amounts reclassified from accumulated other comprehensive loss	3	12	15
Balance as of December 31, 2013	1	(137)	(136)
Other comprehensive loss, before reclassifications	(6)	(71)	(77)
Amounts reclassified from accumulated other comprehensive loss	(1)	8	7
Balance as of December 31, 2014	$(6)	$(200)	$(206)

(1) All amounts are net of income taxes. Amounts in parentheses indicate debits to accumulated other comprehensive loss.

The following table provides details of the reclassifications out of accumulated other comprehensive loss for the years ended December 31, 2014 and 2013 and the ultimate unfavorable impact on net income.

In millions (1)	December 31, 2014	December 31, 2013
Cash flow hedges		
Cost of goods sold (natural gas contracts)	$4	$(1)
Operation and maintenance expense (natural gas contracts)	1	-
Interest expense (interest rate contracts)	-	(3)
Total before income tax	5	(4)
Income tax (expense)/benefit	(2)	1
Cash flow hedges net of income tax	3	(3)
Less noncontrolling interest	2	-
Total cash flow hedges net of income tax	1	(3)
Retirement benefit plans		
Operation and maintenance expense (actuarial losses)(2)	(15)	(25)
Operation and maintenance expense (prior service credits) (2)	2	5
Total before income tax	(13)	(20)
Income tax benefit	5	8
Total retirement benefit plans	(8)	(12)
Total reclassification	$(7)	$(15)

(1) Amounts in parentheses indicate reductions to our net income and to accumulated other comprehensive loss. Except for retirement benefit plan amounts, the net income impacts are immediate.
(2) Amortization of these accumulated other comprehensive loss components is included in the computation of net periodic benefit cost. See Note 6 for additional details about net periodic benefit cost.

Note 10 - Non-Wholly Owned Entities

Variable Interest Entities

On a quarterly basis, we evaluate our variable interests in other entities, primarily ownership interests, to determine if they represent a variable interest entity (VIE) as defined by the authoritative accounting guidance on consolidation, and if so, which party is the primary beneficiary. We have determined that SouthStar, a joint venture owned by us and Piedmont, is our only VIE for which we are the primary beneficiary. This requires us to consolidate its assets, liabilities and Statements of Income. Our conclusion that SouthStar is a VIE resulted from our equal voting rights with Piedmont not being proportional to our economic obligation to absorb 85% of losses or residual returns from the joint venture. We account for our ownership of SouthStar in accordance with authoritative accounting guidance, which is described within Note 2.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to customers in Georgia, and under various other trade names to customers in Illinois, Ohio, Florida, Maryland, Michigan and New York. Following are additional factors we considered in determining that we have the power to direct SouthStar’s activities that most significantly impact its performance.

Operations

Our wholly owned subsidiaries Nicor Gas and Atlanta Gas Light provide the following services, which affect SouthStar’s operations:

- meter reading for SouthStar’s customers in Illinois and Georgia
- maintenance and expansion of the natural gas infrastructure in Illinois and Georgia

- assignment of storage and transportation capacity used in delivering natural gas to SouthStar's customers

Liquidity and capital resources

- guarantees of SouthStar's activities with, and its credit exposure to, its counterparties and to certain natural gas suppliers in support of SouthStar's payment obligations
- support of SouthStar's daily cash management activities and assistance ensuring SouthStar has adequate liquidity and working capital resources by allowing SouthStar to utilize the AGL Capital commercial paper program for its liquidity and working capital requirements in accordance with our services agreement

Back office functions

- accounting, information technology, legal, human resources, credit and internal controls services in accordance with our services agreement

SouthStar's earnings are allocated entirely in accordance with the ownership interests and are seasonal in nature, with the majority occurring during the first and fourth quarters of each year. SouthStar's current assets consist primarily of natural gas inventory, derivative instruments and receivables from its customers. SouthStar also has receivables from us due to its participation in AGL Capital's commercial paper program. SouthStar's current liabilities consist primarily of accrued natural gas costs, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital's commercial paper program.

SouthStar's contractual commitments and obligations, including operating leases and agreements with third-party providers, do not contain terms that would trigger material financial obligations in the event that such contracts were terminated. As a result, our maximum exposure to a loss at SouthStar is considered to be immaterial. SouthStar's creditors have no recourse to our general credit beyond our corporate guarantees that we have provided to SouthStar's counterparties and natural gas suppliers. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees and the aforementioned limited protections related to goodwill and intangible assets, we have not entered into any arrangements that could require us to provide financial support to SouthStar.

Price and volume fluctuations of SouthStar's natural gas inventories can cause significant variations in our working capital and cash flow from operations. Changes in our operating cash flows are also attributable to SouthStar's working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas purchases and cash collateral amounts that SouthStar maintains to facilitate its derivative instruments.

Cash flows used in our investing activities include capital expenditures for SouthStar for the year ended December 31, of $7 million for 2014, $3 million for 2013 and $1 million for 2012. Cash flows used in our financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year. Generally, this distribution occurs in the first quarter of each fiscal year. For the years ended December 31, 2014, 2013 and 2012, SouthStar distributed $17 million, $17 million and $14 million to Piedmont, respectively.

On September 1, 2013, we contributed to SouthStar our Illinois retail energy businesses with approximately 108,000 customers. Additionally, Piedmont contributed to SouthStar $22.5 million in cash to maintain its 15% ownership in the joint venture. In connection with the contribution of our Illinois retail energy businesses, we provided certain limited protections to Piedmont regarding the value of the contributed businesses related to goodwill and other intangible assets. Piedmont's contribution is reflected as an increase to the noncontrolling interest on our Consolidated Statements of Financial Position and a financing activity on our Consolidated Statements of Cash Flows. These funds were used to reduce our commercial paper borrowings. The following table provides additional information on SouthStar's assets and liabilities as of December 31, which are consolidated within our Consolidated Statements of Financial Position.

	2014			2013		
In millions	**Consolidated**	**SouthStar** (1)	**%** (2)	**Consolidated**	**SouthStar** (1)	**%** (2)
Current assets	$2,890	$238	8%	$2,895	$264	9%
Goodwill and other intangible assets	1,952	125	6	1,972	133	7
Long-term assets and other deferred debits	10,067	17	-	9,683	13	-
Total assets	$14,909	$380	3%	$14,550	$410	3%
Current liabilities	$3,219	$71	2%	$3,118	$95	3%
Long-term liabilities and other deferred credits	7,862	-	-	7,819	-	-
Total liabilities	11,081	71	1	10,937	95	1
Equity	3,828	309	8	3,613	315	9
Total liabilities and equity	$14,909	$380	3%	$14,550	$410	3%

(1) These amounts reflect information for SouthStar and exclude intercompany eliminations and the balances of our wholly owned subsidiary with an 85% ownership interest in SouthStar.
(2) SouthStar's percentage of the amount on our Consolidated Statements of Financial Position.

The following table provides information on SouthStar's operating revenues and operating expenses for the years ended December 31, which are consolidated within our Consolidated Statements of Income.

In millions	2014	2013
Operating revenues	$866	$687
Operating expenses		
Cost of goods sold	645	491
Operation and maintenance	87	72
Depreciation and amortization	11	7
Taxes other than income taxes	1	1
Total operating expenses	744	571
Operating income	$122	$116

Equity Method Investments

Triton We have an investment in Triton, a cargo container leasing company, which is included within our "other" non-reportable segment. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement, and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2014, we had invested in seven tranches established by Triton.

Horizon Pipeline We own a 50% interest in a joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC and is included within our midstream operations segment. Horizon Pipeline operates an approximate 70-mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total capacity.

Sawgrass Storage We own a 50% interest in Sawgrass Storage, a joint venture between us and a privately held energy exploration and production company for the development of an underground natural gas storage facility in Louisiana with 30 Bcf of working gas capacity and is included within our midstream operations segment. In December 2013, the joint venture decided to terminate the development of this facility and recognized an impairment loss of $16 million, which reduced the carrying amount of the joint venture's long-lived assets to fair value. Consequently, we recognized our 50% interest in the loss during the fourth quarter of 2013, resulting in an $8 million ($5 million net of tax) charge to operating income.

The carrying amounts of our investments that are accounted for under the equity method at December 31 were as follows:

In millions	2014	2013
Triton	$62	$70
Horizon Pipeline	14	15
Other (1)	4	1
Total	$80	$86

(1) Includes our current investment in PennEast Pipeline of $1 million and Atlantic Coast pipeline of $2 million as of December 31, 2014.

Income from our equity method investments is classified as other income in our Consolidated Statements of Income. The following table provides the income from our equity method investments for the years ended December 31. The majority of our net equity investment income is attributable to our investment in Triton. For more information on our other income, see Note 2. During 2014 and 2013, we received distributions of $17 million from our equity investees.

In millions	2014	2013	2012
Triton	$6	$9	$11
Horizon Pipeline	2	2	2
Other	-	(8)	-
Total	$8	$3	$13

In 2014, we entered into two interstate pipeline joint ventures within our midstream operations segment as described below. Our investments in these joint ventures were immaterial in 2014. The capacity from these joint ventures will further enhance system reliability as well as provide access to a more diverse supply of natural gas. We have concluded that, at present, both are VIEs. We are not considered the primary beneficiary and, therefore, we have not consolidated the financial statements for these joint ventures in our consolidated financial statements because we share in the ability to direct the activities that most significantly impact their economic performance with their other member companies. We have accounted for our investment in these joint ventures using the equity method of accounting, and we have classified the investments in other noncurrent assets in our Consolidated Statements of Financial Position.

PennEast Pipeline On August 11, 2014, we entered into a joint venture in which we hold a 20% ownership interest to develop and operate a 108-mile natural gas pipeline between New Jersey and Pennsylvania with initial transportation capacity of 1 Bcf per day, which may be expanded to 1.2 Bcf per day. Subject to FERC approval, construction is expected to begin in the first quarter of 2017 with a targeted completion date in the fourth quarter of 2017.

Atlantic Coast Pipeline On September 2, 2014, we entered into a joint venture in which we hold a 5% ownership interest to develop and operate a 550-mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day, which may be expanded to 2.0 Bcf per day. Subject to FERC approval, construction is expected to begin in the second half of 2016 with a targeted completion date in the second half of 2018.

Note 11 - Commitments, Guarantees and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services, which are reflected in the table below. The following table illustrates our expected future contractual payments under our obligations and other commitments as of December 31, 2014.

In millions	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020 & thereafter**
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$200	$545	$22	$155	$350	$2,434
Short-term debt	1,175	1,175	-	-	-	-	-
Environmental remediation liabilities (2)	414	87	93	55	47	37	95
Total	$5,295	$1,462	$638	$77	$202	$387	$2,529
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$4,303	$805	$457	$280	$234	$222	$2,305
Interest charges (5)	2,762	179	171	147	146	141	1,978
Operating leases (6)	188	33	31	24	17	18	65
Asset management agreements (7)	32	9	10	7	4	2	-
Standby letters of credit, performance/surety bonds (8)	50	49	1	-	-	-	-
Other	8	3	3	1	1	-	-
Total	$7,343	$1,078	$673	$459	$402	$383	$4,348

(1) Excludes the $75 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $5 million interest rate swaps fair value adjustment. Includes our current portion of long-term debt of $200 million, which matured in January 2015.
(2) Includes charges recoverable through base rates or rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.
(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 51 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2014, and is valued at $142 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2014 and the maturity date of the underlying debt instrument. As of December 31, 2014, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2015.
(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur. We have certain subsidiaries that enter into various financial and performance guarantees and indemnities providing assurance to third parties. We believe the likelihood of payment under our guarantees is remote. No liability has been recorded for such guarantees and indemnifications as the fair value was inconsequential at inception.

Financial guarantees AGL Equipment Leasing Inc. (AEL), a wholly owned subsidiary, holds our interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation was not impacted by the 2014 sale of Tropical Shipping and continues for the life of the Triton partnerships. Any payment is effectively limited to the net assets of AEL, which were less than $1 million at December 31, 2014. We believe the likelihood of any such payment by AEL is remote and as such no liability has been recorded for this obligation.

Indemnities In certain instances, we have undertaken to indemnify current property owners and others against costs associated with the effects and/or remediation of contaminated sites for which we may be responsible under applicable federal or state environmental laws, generally with no limitation as to the amount. These indemnifications relate primarily to ongoing coal tar cleanup, as discussed in Environmental Matters. We believe that the likelihood of payment under our other environmental indemnifications is remote. No liability has been recorded for such indemnifications as the fair value was inconsequential at inception.

Regulatory Matters

In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. In September 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several Marketers that included a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. The Georgia Commission approved the stipulation in December 2014. Over the five-year period, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, will be used to resolve 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light is obligated to resolve 25% and we have recorded a reserve in our Consolidated Statements of Financial Position representing the future estimated cost to purchase the approximately 1.15 Bcf of natural gas. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all certificated Marketers through charges for system retained storage gas as it is used by the certificated Marketers.

On August 7, 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services requesting refunds of $18 million and $22 million, respectively. We filed surrebuttal testimony in December 2014 in this proceeding disputing that any refund is due, as Nicor Gas was authorized to enter into these transactions and revenues associated with such transactions reduced rate payers' costs as either credits to the purchased gas adjustment (PGA) or reductions to base rates consistent with then-current Illinois Commission orders governing these activities. We believe these claims engage in hindsight speculation, which is expressly prohibited in a prudence review examination, and we intend to vigorously defend against these claims. Evidentiary hearings are scheduled for March 2015. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. See Note 3 for additional information.

We are involved in an investigation by the EPA regarding the applicable regulatory requirements for polychlorinated biphenyl in the Nicor Gas distribution system. While we are unable to predict the outcome of this matter or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with this contingency, the final disposition of this matter is not expected to have a material adverse impact on our liquidity or financial condition.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases we are unable to estimate the amount of loss reasonably possible in addition to any amounts already recognized, it is possible that the resolution of these contingencies, either individually or in aggregate, will require us to take charges against, or will result in reductions in, future earnings. Management believes that while the resolution of these contingencies, whether individually or in aggregate, could be material to earnings in a particular period, they will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

PBR Proceeding Nicor Gas' PBR plan was a regulatory plan that provided economic incentives based on natural gas cost performance. The PBR plan went into effect in 2000 and was terminated effective January 1, 2003, following allegations that Nicor Gas acted improperly in connection with the plan. Under this plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers. Since 2002, the amount of the savings and losses required to be shared has been disputed by the CUB and others, with the Illinois Attorney General (IAG) intervening, and subject to extensive contested discovery and other regulatory proceedings before administrative law judges and the Illinois Commission. In 2009, the staff of the Illinois Commission, IAG and CUB requested refunds of $85 million, $255 million and $305 million, respectively.

In February 2012, we committed to a stipulation with the staff of the Illinois Commission for a resolution of the dispute through credits to Nicor Gas customers of $64 million. On November 5, 2012, the Administrative Law Judges issued a proposed order for a refund of $72 million to ratepayers. In the fourth quarter of 2012, we increased our accrual for this dispute by $8 million for a total of $72 million as a result of these developments and their effect on the estimated liability.

On June 7, 2013, the Illinois Commission issued an order requiring us to refund $72 million to current Nicor Gas customers through our PGA mechanism based upon natural gas throughput over 12 months beginning on July 1, 2013. Approximately $43 million was refunded during the first half of 2014, which resulted in the completion of all refunds. On February 28, 2014, the CUB appealed the Illinois Commission's order requesting refunds consistent with its 2009 request to the appellate court in Illinois and Nicor Gas filed its response brief on July 25, 2014. The CUB filed its reply brief on October 17, 2014. There is no set time frame for a final ruling by the appellate court.

Other In addition to the matters set forth above, we are involved with legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. We are unable to determine the ultimate outcome of these other contingencies. We believe that these amounts are appropriately reflected in our consolidated financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 12 - Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors, including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense in the Consolidated Statements of Income are shown in the following table.

In millions	2014	2013	2012
Current income taxes			
Federal	$113	$164	$8
State	38	35	4
Deferred income taxes			
Federal	184	(8)	128
State	17	(11)	20
Amortization of investment tax credits	(2)	(3)	(3)
Total income tax expense	$350	$177	$157

The reconciliations between the statutory federal income tax rate of 35%, the effective rate and the related amount of income tax expense for the years ended December 31, in our Consolidated Statements of Income are presented in the following table.

In millions	2014	2013	2012
Computed tax expense at statutory rate	$325	$165	$151
State income tax, net of federal income tax benefit	36	20	19
Tax effect of net income attributable to the noncontrolling interest	(7)	(7)	(6)
Amortization of investment tax credits	(2)	(3)	(3)
Affordable housing credits	(2)	(2)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Sale of Compass Energy	-	6	-
Other	2	-	-
Total income tax expense on Consolidated Statements of Income	$350	$177	$157

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure the assets and liabilities using income tax rates that are currently in effect. The current portion of our deferred income taxes is recognized within current assets in our Consolidated Statements of Financial Position. We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net current and long-term accumulated deferred income tax liability are as follows.

In millions	As of December 31, 2014	2013
Current accumulated deferred income tax liabilities		
Mark-to-market	$33	$-
Inventory	26	18
Total current accumulated deferred income tax liabilities	59	18
Current accumulated deferred income tax assets		
Compensation accruals	30	19
Lower of cost or market	26	-
Allowance for doubtful accounts	12	10
Mark-to-market	-	24
Other	21	16
Total current accumulated deferred income tax assets	89	69
Valuation allowances (1)	(6)	(8)
Total current accumulated deferred income tax assets, net of valuation allowance	83	61
Net current accumulated deferred income tax asset	$24	$43
Long-term accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$1,801	$1,608
Investments in partnerships	16	18
Acquisition intangibles	14	11
Mark-to-market	12	-
Undistributed earnings of foreign subsidiaries	-	26
Other	85	97
Total long-term accumulated deferred income tax liabilities	1,928	1,760
Long-term accumulated deferred income tax assets		
Unfunded pension and retiree welfare benefit obligation	117	92
Deferred investment tax credits	6	7
Mark-to-market	-	3
Other	95	44
Total long-term accumulated deferred income tax assets	218	146
Valuation allowances (1)	(14)	(14)
Total long-term accumulated deferred income tax assets, net of valuation allowance	204	132
Net long-term accumulated deferred income tax liability	$1,724	$1,628

(1) The total valuation allowance in 2014 and 2013 is $20 million and $22 million respectively. For 2014 the total is comprised of $1 million due to net operating losses of a former non-operating facility that are not allowed in New Jersey and $19 million related to our investment in Triton. For 2013 the total is comprised of $3 million due to net operating losses in New Jersey of a former non-operating facility that are not allowed in New Jersey and $19 million related to our investment in Triton. New Jersey net operating losses expired in 2014, resulting in the reduction of the valuation allowance.

Tax Benefits

As of December 31, 2014, and December 31, 2013, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2015. As of December 31, 2014, we did not have a liability recorded for payment of interest or penalties associated with uncertain tax positions nor did we have any such interest or penalties during 2014 or 2013.

We file a U.S. federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or in any state for years before 2011.

Note 13 - Segment Information

Our reportable segments comprise revenue-generating components of our company for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance. Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. We manage our businesses through four reportable segments - distribution operations, retail operations, wholesale services, midstream operations. Our non-reportable segments are combined and presented as “other segments”.

Effective September 1, 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position, and the financial results of these businesses as of December 31, 2013 are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in this note, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified to a non-reportable segment. See Note 14 for additional information.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states. These utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Although the operations of our distribution operations segment are geographically dispersed, the operating subsidiaries within the distribution operations segment are regulated utilities, with rates determined by individual state regulatory commissions. These natural gas distribution utilities have similar economic and risk characteristics.

We are also involved in several related and complementary businesses. Our retail operations segment includes retail natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, retail operations provides home protection products and services. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, they provide natural gas asset management and/or related logistics services for each of our utilities except Nicor Gas, as well as for non-affiliated companies. Our midstream operations segment includes our non-utility storage and pipeline operations, including the operation of high-deliverability natural gas storage assets. Our “other” non-reportable segments include subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our reportable segments.

The chief operating decision maker of the company is the Chairman, President and Chief Executive Officer, who utilizes EBIT as the primary measure of profit and loss in assessing the results of each segment’s operations. EBIT includes operating income and other income and expenses. Items we do not include in EBIT are income taxes and financing costs, including interest expense, each of which we evaluate on a consolidated basis. Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the years ended December 31, 2014, 2013 and 2012 are shown in the following tables.

2014

In millions	**Distribution operations**	**Retail operations**	**Wholesale services** (1)	**Midstream operations**	**Other segments** (2)	**Intercompany eliminations**	**Consolidated**
Operating revenues from external parties	$3,802	$994	$578	$88	$7	$(84)	$5,385
Intercompany revenues	199	-	-	-	-	(199)	-
Total operating revenues	4,001	994	578	88	7	(283)	5,385
Operating expenses							
Cost of goods sold	2,223	683	77	57	-	(275)	2,765
Operation and maintenance	699	147	75	26	-	(8)	939
Depreciation and amortization	317	28	1	18	16	-	380
Taxes other than income taxes	189	4	3	6	6	-	208
Total operating expenses	3,428	862	156	107	22	(283)	4,292
Gain (loss) on disposition of assets	-	-	3	-	(1)	-	2
Operating income (loss)	573	132	425	(19)	(16)	-	1,095
Other income (expense)	8	-	(3)	2	7	-	14
EBIT	$581	$132	$422	$(17)	$(9)	$-	$1,109
Identifiable and total assets (3)	$12,041	$670	$1,402	$694	$9,723	$(9,621)	$14,909
Capital expenditures	$715	$11	$2	$15	$26	$-	$769

2013

In millions	**Distribution operations**	**Retail operations**	**Wholesale services** (1)	**Midstream operations**	**Other segments** (2)	**Intercompany eliminations**	**Consolidated**
Operating revenues from external parties	$3,230	$858	$60	$74	$8	$(21)	$4,209
Intercompany revenues	182	-	-	-	-	(182)	-
Total operating revenues	3,412	858	60	74	8	(203)	4,209
Operating expenses							
Cost of goods sold	1,687	564	21	33	-	(195)	2,110
Operation and maintenance	687	132	49	24	3	(8)	887
Depreciation and amortization	339	27	1	17	13	-	397
Taxes other than income taxes	167	3	3	5	9	-	187
Total operating expenses	2,880	726	74	79	25	(203)	3,581
Gain on disposition of assets	-	-	11	-	-	-	11
Operating income (loss)	532	132	(3)	(5)	(17)	-	639
Other income (expense)	14	-	-	(5)	7	-	16
EBIT	$546	$132	$(3)	$(10)	$(10)	$-	$655
Identifiable and total assets (3)	$11,634	$685	$1,163	$713	$10,160	$(10,088)	$14,267
Capital expenditures	$684	$9	$2	$12	$24	$-	$731

2012

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other segments (2)	Intercompany eliminations	Consolidated
Operating revenues from external parties	$2,691	$733	$88	$78	$7	$(35)	$3,562
Intercompany revenues	167	2	-	-	-	(169)	-
Total operating revenues	2,858	735	88	78	7	(204)	3,562
Operating expenses							
Cost of goods sold	1,221	488	38	32	-	(196)	1,583
Operation and maintenance	642	114	48	19	1	(8)	816
Depreciation and amortization	347	18	2	14	13	-	394
Nicor merger expenses (4)	-	-	-	-	20	-	20
Taxes other than income taxes	140	4	4	5	6	-	159
Total operating expenses	2,350	624	92	70	40	(204)	2,972
Operating income (loss)	508	111	(4)	8	(33)	-	590
Other income	9	-	1	2	12	-	24
EBIT	$517	$111	$(3)	$10	$(21)	$-	$614
Identifiable and total assets (3)	$11,256	$506	$1,218	$720	$9,848	$(9,769)	$13,779
Capital expenditures	$649	$8	$3	$62	$53	$-	$775

(1) The revenues for wholesale services are netted with costs associated with its energy and risk management activities. A reconciliation of our operating revenues and our intercompany revenues for the years ended December 31, are shown in the following table. Wholesale services 2014 operating revenues are related to colder-than-normal weather and extreme volatility and are not indicative of future performance.

In millions	Third party gross revenues	Intercompany revenues	Total gross revenues	Less gross gas costs	Operating revenues
2014	$10,709	$718	$11,427	$10,849	$578
2013	7,681	417	8,098	8,038	60
2012	6,089	350	6,439	6,351	88

(2) Our other non-reportable segments now also include our investment in Triton, which was part of our cargo shipping segment that is classified as discontinued operations. For more information, see Note 14.

(3) Identifiable assets are those used in each segment’s operations and exclude assets held for sale.

(4) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.

Note 14 - Discontinued Operations

On September 1, 2014, we closed on the sale of Tropical Shipping to an unrelated third party. The after-tax cash proceeds and distributions from the transaction were approximately $225 million. We determined that the cumulative foreign earnings of Tropical Shipping would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million, of which $31 million was recorded in the first quarter of 2014, and the remaining $29 million was recorded in the third quarter of 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash.

During the first quarter of 2014, based upon the negotiated sales price, we also recorded a goodwill impairment charge of $19 million, for which there is no income tax benefit. Additionally, we recognized a total of $7 million charge in the second and third quarters of 2014 related to the suspension of depreciation and amortization for assets that we were not compensated for by the buyer.

The assets and liabilities of Tropical Shipping classified as held for sale on the Consolidated Statements of Financial Position are as follows:

In millions	**December 31, 2013**
Current assets	
Cash and cash equivalents	$24
Short-term investments	1
Receivables	36
Inventories	9
Other	1
Total current assets	71
Long-term assets and other deferred debits	
Property, plant and equipment, net	124
Goodwill	61
Intangible assets	19
Other	8
Total long-term assets and other deferred debits	212
Total assets held for sale	$283
Current liabilities	
Accrued expenses	$7
Other accounts payable - trade	11
Other	22
Total liabilities held for sale	$40

The financial results of these businesses are reflected as discontinued operations, and all prior periods presented have been recast to reflect the discontinued operations. The components of discontinued operations recorded on the Consolidated Statements of Income as of December 31, are as follows:

In millions	**2014**	**2013**	**2012**
Operating revenues	$243	$365	$342
Operating expenses			
Cost of goods sold	149	222	208
Operation and maintenance (1)	75	110	106
Depreciation and amortization (2)	5	19	22
Taxes other than income taxes	5	6	6
Loss on sale and goodwill impairment (3)	28	-	-
Total operating expenses	262	357	342
Operating (loss) income	(19)	8	-
(Loss) income before income taxes	(19)	8	-
Income tax expense (4)	(61)	3	(1)
(Loss) income from discontinued operations, net of tax	$(80)	$5	$1

(1) Includes $1 million for another business not related to Tropical Shipping that we discontinued in 2014 and was included in our "other" non-reportable segment.
(2) We ceased depreciating and amortizing Tropical Shipping's assets on April 4, 2014, as a result of entering into an agreement to sell this business and the assets were classified as held for sale.
(3) Primarily relates to the suspension of depreciation and amortization during 2014 totaling $7 million, and $19 million of goodwill attributable to Tropical Shipping that was impaired as of March 31, 2014, based on the negotiated sales price.
(4) Includes $60 million that was recorded in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded.

Note 15 - Selected Quarterly Financial Data (Unaudited)

The variance in our quarterly earnings is primarily the result of the seasonal nature of the distribution of natural gas to customers, the volatility within our wholesale services segment and the sale of our cargo shipping segment in 2014. During the Heating Season, natural gas usage and operating revenues are generally higher at our distribution operations and retail operations segments as more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. However, our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively uniformly over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality.

Our 2014 operating revenues and operating income were higher than 2013, primarily as a result of significantly colder-than-normal weather in 2014, volatility in the natural gas market and transportation constraints in the Northeast and Midwest. Our quarterly financial data for 2014 and 2013 are summarized below.

In millions, except per share amounts	**March 31**	**June 30**	**September 30**	**December 31**
2014				
Operating revenues	$2,462	$889	$589	$1,445
Operating income	592	139	78	286
EBIT	595	141	81	292
Income from continuing operations	346	59	23	152
Income from continuing operations attributable to AGL Resources Inc.	334	57	23	148
(Loss) income from discontinued operations, net of tax	(50)	1	(31)	-
Net income (loss) attributable to AGL Resources Inc.	284	58	(8)	148
Basic earnings (loss) per common share:				
Continuing operations	2.82	0.48	0.19	1.24
Discontinued operations	(0.43)	0.01	(0.25)	-
Diluted earnings (loss) per common share:				
Continuing operations	2.81	0.48	0.19	1.24
Discontinued operations	(0.43)	0.01	(0.25)	-
2013				
Operating revenues	$1,612	$805	$574	$1,218
Operating income	290	113	70	166
EBIT	295	119	77	164
Income from continuing operations	159	45	24	80
Income from continuing operations attributable to AGL Resources Inc.	149	44	24	73
Income (loss) from discontinued operations, net of tax	1	(1)	1	4
Net income attributable to AGL Resources Inc.	150	43	25	77
Basic earnings (loss) per common share:				
Continuing operations	1.27	0.38	0.20	0.61
Discontinued operations	0.01	(0.01)	0.01	0.03
Diluted earnings (loss) per common share:				
Continuing operations	1.26	0.38	0.20	0.61
Discontinued operations	0.01	(0.01)	0.01	0.03

Our basic and diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per common share attributable to AGL Resources Inc. common shareholders shown in the Consolidated Statements of Income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of December 31, 2014. No system of controls, no matter how well-designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases. Our disclosure controls and procedures, however, are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation and considering the remediation efforts described below, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014. Our disclosure controls and procedures are designed to ensure that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Remediation of Previously Disclosed Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014, we did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company's consolidated financial statements. Our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were not effective as of September 30, 2014 because of the material weakness.

We revised our consolidated financial statements for the years ended December 31, 2013, 2012 and 2011, for each of the quarterly periods during the year ended December 31, 2013, and for the quarters ended March 31, 2014 and June 30, 2014 to reflect certain accounting adjustments. We amended our Annual Report on Form 10-K/A for the year ended December 31, 2013, and our Quarterly Reports on Form 10-Q/A for the quarterly periods ending March 31, 2014 and June 30, 2014, to reflect those adjustments and the conclusions by our principal executive officer and our principal financial officer that our disclosure controls and procedures were not effective and by our management that our internal control over financial reporting were not effective as of December 31, 2013. Refer to "Management's Annual Report on Internal Control over Financial Reporting" within Item 8 and Item 9A Controls and Procedures in our Annual Report on Form 10-K/A for the year ended December 31, 2013, for further discussion of our material weakness in internal control over financial reporting.

We committed to remediating the material weakness and, as such, implemented changes to our internal control over financial reporting. We implemented additional procedures to address the underlying causes of the material weakness prior to filing our amended 2013 Annual Report on Form 10-K/A, and continued to implement changes and improvements in our internal control over financial reporting to remediate the control deficiency that caused the material weakness. During the fourth quarter of 2014, the following actions have been implemented:

- Completed training for all appropriate personnel regarding the applicable accounting guidance and requirements through internal training meetings and training by an outside expert to employees in technical, general and regulatory accounting functions, internal audit, and management positions.
- Reviewed all regulatory programs to ensure the proper evaluation of deferral components and proper treatment of allowed versus incurred costs pursuant to the relevant accounting guidance.
- Created a process and designed controls to capture and calculate allowed versus incurred costs and to record appropriate amounts in the consolidated financial statements. We identified appropriate processes, reviews and other controls to ensure accurate amounts were appropriately reflected in our consolidated financial statements.
- Conducted a review of our organization structure, reporting relationships and adequacy of staffing levels and made specific staffing changes as a result of our review.
- The procedures described above have been implemented and controls have been successfully tested.

Management is committed to a strong internal control environment. With full implementation and testing of the design and operating effectiveness of the newly implemented and revised controls, the actions described above successfully remediated the material weakness in our internal control over financial reporting and our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective and our management concluded that our internal control over financial reporting were effective as of December 31, 2014.

Changes in Internal Control over Financial Reporting

The changes in the aforementioned remediation efforts were changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Reports of Management and Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

Management has assessed, and our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited, our internal control over financial reporting as of December 31, 2014. The unqualified reports of management and PricewaterhouseCoopers LLP are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 59	
Chairman, President and Chief Executive Officer	October 2007 - Present
Andrew W. Evans, Age 48	
Executive Vice President and Chief Financial Officer	November 2010 - Present
Executive Vice President, Chief Financial Officer and Treasurer	June 2009 - November 2010
Henry P. Linginfelter, Age 54	
Executive Vice President, Distribution Operations	December 2011 - Present
Executive Vice President, Utility Operations	June 2007 - December 2011
Melanie M. Platt, Age 60	
Executive Vice President, Chief People Officer	December 2011 - Present
Senior Vice President, Human Resources and Marketing Communications	November 2008 - December 2011
Paul R. Shlanta, Age 57	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 - Present
Peter I. Tumminello, Age 52	
Executive Vice President, Wholesale Services, and President Sequent	December 2011 - Present
President, Sequent	April 2010 - December 2011
Executive Vice President, Business Development and Support, Sequent	February 2007 - April 2010

The other information required by this item with respect to directors will be set forth under the captions “Proposal 1 - Election of Directors,” “Corporate Governance - Ethics and Compliance Program,” and “Corporate Governance - Committees of the Board” in the Proxy Statement for our 2015 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions “Compensation Committee Report,” “Compensation Committee Interlocks and Insider Participation,” “Director Compensation,” “Compensation Discussion and Analysis” and “Executive Compensation” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption “Compensation Committee Report” which is specifically not so incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be set forth under the captions “Security Ownership of Certain Beneficial Owners and Management” and “Executive Compensation - Equity Compensation Plan Information” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth under the captions “Corporate Governance - Director Independence” and “- Policy on Related Person Transactions” and “Certain Relationships and Related Transactions” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under the caption “Proposal 2 - Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2015” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

- Report of Independent Registered Public Accounting Firm
- Management’s Report on Internal Control Over Financial Reporting

(1) Financial Statements Included in Item 8 are the following:

- Report of Independent Registered Public Accounting Firm
- Management’s Report on Internal Control Over Financial Reporting
- Consolidated Statements of Financial Position as of December 31, 2014 and 2013
- Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Equity for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012
- Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2014. Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

(3) Exhibits

Exhibit Number	Description of Exhibit	Filer	The Filings Referenced for Incorporation by Reference
2.1	Agreement and Plan of Merger, as amended, dated December 6, 2010	AGL Resources	December 7, 2010, Form 8-K, Exhibit 2.1
2.2	Waiver entered into as of February 4, 2011	AGL Resources	February 9, 2011, Form 8-K, Exhibit 2.1
2.3	Stock Purchase Agreement by and among Aqua Acquisition Corp., Ottawa Acquisition LLC and Birdsall, Inc.(1)	AGL Resources	November 25, 2014, Form 10-Q/A, Exhibit 2
3.1	Amended and Restated Articles of Incorporation	AGL Resources	December 13, 2011, Form 8-K, Exhibit 3.1
3.2	Bylaws, as amended	AGL Resources	July 31, 2014, Form 8-K, Exhibit 3.1
4.1	Specimen Form of Common Stock certificate	AGL Resources	September 30, 2007, Form 10-Q, Exhibit 4.1
4.2.a	Form of AGL Capital Corporation 6.00% Senior Notes due 2034	AGL Resources	September 27, 2004, Form 8-K, Exhibit 4.1
4.2.b	Form of Guarantee of AGL Resources Inc. dated September 27, 2004	AGL Resources	September 27, 2004, Form 8-K, Exhibit 4.3
4.3.a	AGL Capital Corporation 4.95% Senior Notes due 2015	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.1
4.3.b	Guarantee of AGL Resources Inc. dated December 20, 2004	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.3
4.4.a	AGL Capital Corporation 6.375% Senior Notes due 2016	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.1
4.4.b	Guarantee of AGL Resources Inc. dated December 14, 2007	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.2
4.5.a	AGL Capital Corporation 5.25% Senior Notes due 2019	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.1

4.5.b	Guarantee of AGL Resources Inc. dated August 10, 2009	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.2
4.6.a	AGL Capital Corporation 5.875% Senior Notes due 2041	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.1
4.6.b	Guarantee of AGL Resources Inc. dated March 21, 2011	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.2
4.7.a	Form of AGL Capital Corporation 3.50% Senior Notes due 2021	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.1
4.7.b	Form of Guarantee of AGL Resources Inc. dated September 2011	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.2
4.8.a	Form of AGL Capital Corporation Series A Senior Notes due 2016	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.1
4.8.b	Form of AGL Capital Corporation Series B Senior Notes due 2018	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.2
4.9.a	AGL Capital Corporation 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.9.b	AGL Resources Inc. Guarantee related to the 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.10.a	Indenture dated December 1, 1989	Atlanta Gas Light	File No. 33-32274, Form S-3, Exhibit 4(a)
4.10.b	First Supplemental Indenture dated March 16, 1992	Atlanta Gas Light	File No. 33-46419, Form S-3, Exhibit 4(a)
4.11	Indenture dated February 20, 2001	AGL Resources	September 17, 2001, File No. 333-69500, Form S-3, Exhibit 4.2
4.12.a	Indenture dated January 1, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.01
4.12.b	Indenture dated February 9, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.02
4.12.c	Supplemental Indenture dated February 15, 1998	Nicor Gas	December 31, 1997, Form 10-K, Exhibit 4.19
4.12.d	Supplemental Indenture dated May 15, 2001	Nicor Gas	July 20, 2001, File No. 333-65486, Form S-3, Exhibit 4.18
4.12.e	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.09
4.12.f	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.10
4.12.g	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.11
4.12.h	Supplemental Indenture dated December 1, 2006	Nicor Gas	December 31, 2006, Form 10-K, Exhibit 4.11
4.12.i	Supplemental Indenture dated August 1, 2008	Nicor Gas	September 30, 2008, Form 10-Q, Exhibit 4.01
4.12.j	Supplemental Indenture dated July 23, 2009	Nicor Gas	June 30, 2009, Form 10-Q, Exhibit 4.01
4.12.k	Supplemental Indenture dated February 1, 2011	Nicor Gas	December 31, 2010, Form 10-K, Exhibit 4.12
4.12.l	Supplemental Indenture dated October 26, 2012	Nicor Gas	September 30, 2012, Form 10-Q, Exhibit 4
10.1.a +	2006 Non-Employee Directors Equity Compensation Plan, amended and restated as of December 9, 2011	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.2
10.1.b +	1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 1997, Form 10-Q, Exhibit 10.1.b
10.1.c +	First Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	March 31, 2000, Form 10-Q, Exhibit 10.5
10.1.d +	Second Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.4
10.1.e +	Third Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.5
10.1.f +	Fourth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.m
10.1.g +	Fifth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.l
10.1.h +	Form of Stock Award Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.aj
10.1.i +	Form of Nonqualified Stock Option Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.ak
10.1.j +	Form of Director Indemnification Agreement dated April 28, 2004	AGL Resources	June 30, 2004, Form 10-Q, Exhibit 10.3
10.1.k +	Long-Term Incentive Plan, as amended and restated as of January 1, 2002	AGL Resources	March 31, 2002, Form 10-Q, Exhibit 99.2
10.1.l +	First amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.b
10.1.m +	Second amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.l

10.1.n +	Third amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ad
10.1.o +	Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	March 14, 2011, Schedule 14A, Annex A
10.1.p +	Form of Restricted Stock Unit Agreement under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2011, Form 10-K, Exhibit 10.1.ae
10.1.q +	Form of Restricted Stock Agreement under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2011, Form 10-K, Exhibit 10.1.af
10.1.r +	Form of Performance Share Unit Award under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1r
10.1.s +	2007 Omnibus Performance Incentive Plan	AGL Resources	March 19, 2007, Schedule 14A, Annex A
10.1.t +	First Amendment to the 2007 Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ai
10.1.u +	Form of Incentive Stock Option Agreement – 2007 Omnibus Performance Incentive Plan	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.b
10.1.v +	Form of Nonqualified Stock Option Agreement – 2007 Omnibus Performance Incentive Plan	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.c
10.1.w +	Form of Incentive Stock Option Agreement and Nonqualified Stock Option Agreement for key employees (LTIP)	AGL Resources	September 30, 2004, Form 10-Q, Exhibit 10.1
10.1.x +	Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.1
10.1.y +	Form of Nonqualified Stock Option Agreement with the reload provision (Officer Incentive Plan)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.2
10.1.z +	Nonqualified Savings Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.av
10.1.aa +	First Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.aa
10.1.ab +	Second Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ab
10.1.ac +	Third Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ac
10.1.ad +	Description of Supplemental Executive Retirement Plan for John W. Somerhalder II	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ay
10.1.ae +	Excess Benefit Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.az
10.1.af +	Form of Continuity Agreement dated December 19, 2013	AGL Resources	December 19, 2013, Form 8-K, Exhibit 10.1
10.1.ag +	Description of compensation for each of John W. Somerhalder II, Andrew W. Evans, Henry P. Linginfelter, Paul R. Shlanta and Peter I. Tumminello (our Named Executive Officers for the year ended December 31, 2014)	AGL Resources	Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held April 29, 2014, filed March 18, 2014.
10.2.a	Form of Commercial Paper Dealer Agreement	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.79
10.2.b	Guarantee dated October 5, 2000 of payments on promissory notes	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.80
10.4	Note Purchase Agreement dated August 31, 2011	AGL Resources	September 7, 2011, Form 8-K, Exhibit 10.1
10.5	Final Allocation Agreement dated January 3, 2008	Nicor	December 31, 2007, Form 10-K, Exhibit 10.64
10.6	Second Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC dated September 6, 2013 by and between Georgia Natural Gas Company and Piedmont Energy Company	AGL Resources	September 30, 2013, Form 10-Q, Exhibit 10
10.7	Credit Agreement dated as of December 15, 2011 (2)	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.1
10.8.a	Amended and Restated Credit Agreement dated as of November 10, 2011 (3)	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.1
10.8.b	Guarantee Agreement dated as of November 10, 2011	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.2

10.9	Bank Rate Mode Covenants Agreement, dated as of February 26, 2013	AGL Resources	March 1, 2013, Form 8-K, Exhibit 10.1
10.10	Loan Agreement dated as of February 1, 2013	AGL Resources	March 1, 2013, Form 8-K, Exhibit 10.2
10.11	Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.1
10.12	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.2
10.13	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.3
10.14	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.4
12	Statement of Computation of Ratio of Earnings to Fixed Charges	AGL Resources	Filed herewith
14	Code of Ethics for the Chief Executive Officer and Senior Financial Officers	AGL Resources	December 31, 2004, Form 10-K, Exhibit 14
21	Subsidiaries of AGL Resources Inc.	AGL Resources	Filed herewith
23	Consent of PricewaterhouseCoopers LLP	AGL Resources	Filed herewith
24	Powers of Attorney	AGL Resources	Included on signature page hereto
31.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
31.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
32.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
32.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
101.INS	XBRL Instance Document	AGL Resources	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema	AGL Resources	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	AGL Resources	Filed herewith
101.DEF	XBRL Taxonomy Definition Linkbase	AGL Resources	Filed herewith
101.LAB	XBRL Taxonomy Extension Labels Linkbase	AGL Resources	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	AGL Resources	Filed herewith

\+ Management contract, compensatory plan or arrangement.

(1) Portions of this exhibit have been omitted pursuant to a request for confidential treatment with the SEC. The omitted portions have been separately filed with the SEC.

(2) In November 2013, the Credit Agreement commitment terms were extended to a maturity date of December 15, 2017 via an approved extension request.

(3) In November 2013, the Amended and Restated Credit Agreement commitment terms were extended to a maturity date of November 10, 2017 via an approved extension request.

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

(c) Financial statement schedules filed as part of this report.

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 11, 2015.

AGL RESOURCES INC.

By: /s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2014, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 11, 2015.

Signatures	Title	Signatures	Title
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)	/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director
		/s/ Dennis M. Love Dennis M. Love	Director
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	/s/ Dean R. O'Hare Dean R. O'Hare	Director
		/s/ Armando J. Olivera Armando J. Olivera	Director
/s/ Bryan E. Seas Bryan E. Seas	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	/s/ John E. Rau John E. Rau	Director
/s/ Sandra N. Bane Sandra N. Bane	Director	/s/ James A. Rubright James A. Rubright	Director
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director	/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Norman R. Bobins Norman R. Bobins	Director	/s/ Henry C. Wolf Henry C. Wolf	Director
/s/ Charles R. Crisp Charles R. Crisp	Director		
/s/ Brenda J. Gaines Brenda J. Gaines	Director		
/s/ Arthur E. Johnson Arthur E. Johnson	Director		

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2014.

In millions	Balance at beginning of period	Additions: Charged to costs and expenses	Additions: Charged to other accounts	Deductions	Balance at end of period
2012					
Allowance for uncollectible accounts	$17	$25	$3	$(17)	$28
Income tax valuation	3	-	19	-	22
2013					
Allowance for uncollectible accounts	$28	$37	$-	$(36)	$29
Income tax valuation	22	-	-	-	22
2014					
Allowance for uncollectible accounts	$29	$54	$2	$(50)	$35
Income tax valuation	22	-	-	(2)	20

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Exhibit 31.1 – Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a)

CERTIFICATIONS

I, John W. Somerhalder II, certify that:

1. I have reviewed this annual report on Form 10-K of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2015

/s/ John W. Somerhalder II
Chairman, President and Chief Executive Officer

Exhibit 31.2 – Certification of Andrew W. Evans pursuant to Rule 13a – 14(a)

CERTIFICATIONS

I, Andrew W. Evans, certify that:

1. I have reviewed this annual report on Form 10-K of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2015

/s/ Andrew W. Evans
Executive Vice President and Chief Financial Officer

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Corporate Information

Annual Meeting

The 2015 annual meeting of shareholders will be held Tuesday, April 28, 2015, at AGL Resources' corporate headquarters, Ten Peachtree Place, N.E., Atlanta, GA 30309.

ResourcesDIRECT™

New investors may make an initial investment, and shareholders of record may acquire additional shares of our common stock, through ResourcesDIRECT™ without paying brokerage fees or service charges. Initial cash investments, quarterly cash dividends and/or optional cash purchases may be invested through the plan prospectus and enrollment materials. Contact our transfer agent at 800-468-9716 or visit our website at aglresources.com.

Holders of Common Stock, Stock Price and Dividend Information

At February 4, 2015, there were 21,551 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2014 and 2013 is as follows:

2014

Quarter ended	Sales price of common stock High	Low	Close	Cash dividend per common share
March 31, 2014	$49.84	$45.17	$48.96	$0.49
June 30, 2014	55.10	48.29	55.03	0.49
September 30, 2014	55.30	48.72	51.34	0.49
December 31, 2014	56.67	50.10	54.51	0.49
				$1.96

2013

Quarter ended	Sales price of common stock High	Low	Close	Cash dividend per common share
March 31, 2013	$42.37	$38.86	$41.95	$0.47
June 30, 2013	44.85	41.21	42.86	0.47
September 30, 2013	47.00	41.94	46.03	0.47
December 31, 2013	49.31	44.56	47.23	0.47
				$1.88

We have paid 269 consecutive quarterly dividends to common shareholders beginning in 1948, historically four times a year: March 1, June 1, September 1 and December 1. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors. In February 2015, we increased our quarterly dividend to $0.51 per share.

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Stock Exchange Listing

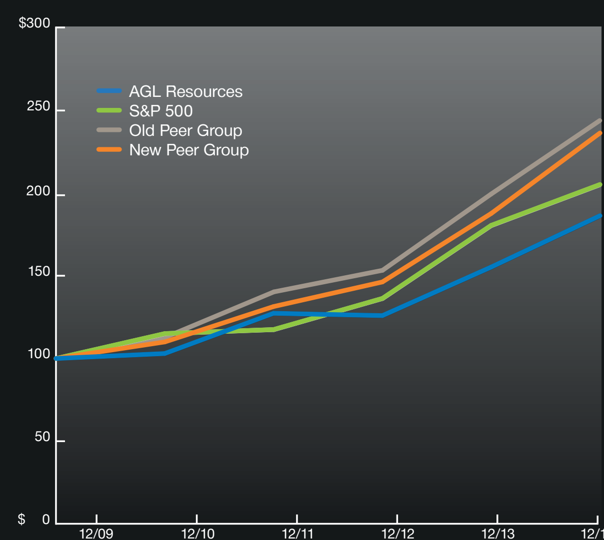
Our common stock is traded on the New York Stock Exchange under the symbol "GAS" and quoted in The Wall Street Journal as "AGL Res."

Comparison of Five-Year Cumulative Total Return*

The graph below compares the cumulative five-year total return provided shareholders on AGL Resources Inc's common stock relative to the cumulative total returns of the S&P 500© index and two customized peer groups of 12 companies each, whose individual companies are listed in footnotes 1 and 2 below. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our common stock, in each index and in each of the peer groups on 12/31/2009 and its relative performance is tracked through 12/31/2014.

[1] There are 12 companies included in the company's new customized peer group which are Atmos Energy Corp., Centerpoint Energy Inc., Integrys Energy Group Inc., New Jersey Resources Corp., Nisource Inc., Piedmont Natural Gas Company Inc., Sempra Energy, Southwest Gas Corp., The Laclede Group Inc., UGI Corp., Vectren Corp. and WGL Holdings Inc.

[2] The 12 companies included in the company's old customized peer group are Atmos Energy Corp., Centerpoint Energy Inc., Integrys Energy Group Inc., New Jersey Resources Corp., Nisource Inc., Oneok Inc., Piedmont Natural Gas Company Inc., Sempra Energy, Southwest Gas Corp., UGI Corp., Vectren Corp. and WGL Holdings Inc.



	12/09	12/10	12/11	12/12	12/13	12/14
AGL Resources Inc	$100.00	$103.00	$127.32	$125.91	$155.24	$186.26
S&P 500	100.00	115.06	117.49	136.30	180.44	205.14
Old Peer Group	100.00	112.82	140.32	153.36	199.52	244.00
New Peer Group	100.00	110.97	132.38	146.26	185.58	236.43

* $100 invested on 12/31/09 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

AGL Resources®

aglresources.com

Exhibit 4

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

SCHEDULE 14A

Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934

Filed by the Registrant ☒ Filed by a Party other than the Registrant ☐

Check the appropriate box:

☐ Preliminary Proxy Statement

☐ **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**

☒ Definitive Proxy Statement

☐ Definitive Additional Materials

☐ Soliciting Material Pursuant to Section 240.14a-12

AGL RESOURCES INC.

(Name of Registrant as Specified in Its Charter)

Payment of Filing Fee (Check the appropriate box):

☒ No fee required.

☐ Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11:

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

☐ Fee paid previously with preliminary materials.

☐ Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount previously paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

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JOHN W. SOMERHALDER II
Chairman, President and Chief Executive Officer

March 17, 2015

To Our Shareholders:

On behalf of the board of directors, I am pleased to invite you to attend AGL Resources' 2015 annual meeting of shareholders to be held on Tuesday, April 28, 2015, at our corporate headquarters at Ten Peachtree Place, Atlanta, Georgia. The meeting will start at 10:00 a.m., Eastern time. A map with directions is included in the attached proxy statement. **Please note that you will need to present an admission ticket and picture identification in order to attend the meeting in person.** Please see page 6 of the attached proxy statement for more information about attending the meeting in person. The matters to be acted upon at the meeting are described in the Notice of Annual Meeting of Shareholders and Proxy Statement. During the annual meeting of shareholders, we will discuss our efforts and achievements in 2014. We will update shareholders on our business plans for 2015. Our directors, officers and other employees will be available to answer any questions you may have.

Your vote is very important to us. Regardless of the number of shares you own, please vote. You may vote by telephone (using the toll-free number on your proxy or vote instruction card), internet (using the address provided on your proxy or vote instruction card), or paper proxy or vote instruction card. Please see page 2 of the attached proxy statement or your enclosed proxy or vote instruction card for more detailed information about the various options for voting your shares.

Thank you for your ongoing ownership and support. We hope to see you at our annual meeting.

Sincerely,

John W. Somerhalder II

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AGL Resources®

Ten Peachtree Place
Atlanta, Georgia 30309

NOTICE OF 2015 ANNUAL MEETING OF SHAREHOLDERS

Time and Date:	10:00 a.m., Eastern time, Tuesday, April 28, 2015
Place:	Ten Peachtree Place, Atlanta, Georgia
Items of Business:	— Elect fifteen directors to serve until the 2016 annual meeting; — Ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2015; — Approve a non-binding resolution to approve the compensation of our named executive officers; — Approve an amendment to the Company’s amended and restated articles of incorporation to provide holders of at least 25% of the voting power of all outstanding shares entitled to vote the right to call a special meeting of shareholders; — Consider and act upon the shareholder proposal regarding an independent chairman policy as described in this proxy statement, if properly presented at the annual meeting; — Consider and act upon the shareholder proposal regarding the adoption of quantitative goals for reducing greenhouse gas emissions and report on plans to achieve such goals as described in this proxy statement, if properly presented at the annual meeting; and — Transact such other business as may properly come before the annual meeting or any adjournments.
Who May Vote:	You may vote if you owned shares of our common stock at the close of business on February 17, 2015 (the record date).
Proxy Voting:	Your vote is important. Please vote in one of these ways: — use the toll-free telephone number shown on the enclosed proxy or vote instruction card; — visit the website listed on your proxy or vote instruction card; or — mark, sign, date and promptly return the enclosed proxy or vote instruction card in the enclosed postage-paid envelope.
Proxy Statement:	A copy of our proxy statement for the annual meeting, which contains information that is relevant to the proposals to be voted on at the annual meeting, is attached.
Annual Report:	A copy of our 2014 annual report, which contains financial and other information about our business, is enclosed.
Date of Availability:	On or about March 17, 2015, we will mail to certain shareholders a Notice of Internet Availability of Proxy Materials containing instructions on how to access our proxy statement and 2014 annual report and how to vote online. All other shareholders will receive the proxy statement and annual report by mail.

By Order of the Board of Directors,

Myra C. Bierria

Myra C. Bierria
Corporate Secretary

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IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON APRIL 28, 2015:

A copy of our combined 2014 annual report and Form 10-K for 2014 is being made available with this proxy statement. You may receive a stand-alone copy of our 2014 Form 10-K free of charge upon written request directed to:

AGL Resources Inc.
Attention: Investor Relations
P.O. Box 4569, Location 1071
Atlanta, Georgia 30302-4569
Our proxy statement and our 2014 annual report and Form 10-K may be accessed at ***www.proxyvote.com***
and our website at ***www.aglresources.com***

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PROXY STATEMENT

ABOUT THE ANNUAL MEETING

Who is soliciting my proxy?

The board of directors of AGL Resources is providing you these proxy materials in connection with the solicitation of proxies to be voted at our 2015 annual meeting of shareholders and at any postponement or adjournment of the annual meeting. The proxies will be voted in accordance with your instructions by John W. Somerhalder II, our chairman, president and chief executive officer; Paul R. Shlanta, our executive vice president, general counsel and chief ethics and compliance officer; and Andrew W. Evans, our executive vice president and chief financial officer, or any of them. If your shares are held in our AGL Resources Inc. Retirement Savings Plus Plan (the “Retirement Savings Plus Plan” or the “AGL 401(k) Plan”) or Nicor Gas Thrift Plan, your proxy will be voted by Merrill Lynch Bank and Trust Co., FSB, which is the trustee for these plans. The trustee of the AGL 401(k) Plan will vote your shares in accordance with your instructions and if you fail to provide voting instructions, the trustee will vote your shares in accordance with the discretionary instructions of the Administrative Committee of the 401(k) plans. It is expected that the Administrative Committee will instruct the trustee of the AGL 401(k) Plan to vote your shares in accordance with your telephone, internet or written proxy vote, or if you do not vote, “FOR” all nominees listed in proposal 1, “FOR” proposals 2, 3 and 4, and “AGAINST” proposals 5 and 6, and as instructed by the Administrative Committee on any other proposals that may properly come before the meeting. The trustee of the Nicor Gas Thrift Plan will vote your shares in accordance with your instructions, and if you fail to give the trustee proper instructions, it will vote your shares in the same proportion that other participants in the plan have voted their shares.

Why did I receive a Notice of Internet Availability of Proxy Materials (Notice) in the mail instead of a printed set of proxy materials?

Pursuant to the rules of the Securities and Exchange Commission (“SEC”), we are permitted to furnish our proxy materials over the internet to our shareholders by delivering a Notice in the mail. We are sending the Notice to certain record and beneficial shareholders. These shareholders have the ability to access the proxy materials, including our proxy statement and annual report, at *www.proxyvote.com* or to request a printed or email set of the proxy materials. Instructions on how to access the proxy materials over the internet or to receive a printed set may be found in the Notice. Shareholders who receive a printed set of proxy materials will not receive the Notice, but may still access our proxy materials over the internet at *www.proxyvote.com*.

When will Proxy Materials be provided to shareholders?

A Notice of Internet Availability of Proxy Materials or this Proxy Statement is first being mailed to shareholders on or about March 17, 2015.

Important Notice Regarding the Availability of Proxy Materials for the Shareholder Meeting to be Held on April 28, 2015.

The proxy statement and annual report are available at www.proxyvote.com

What will I be voting on?

You will be voting on:

- Proposal 1—the election of 15 directors to serve until the 2016 annual meeting;

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- Proposal 2—the ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2015;
- Proposal 3—the approval of a non-binding resolution to approve the compensation of our Named Executive Officers, as described in the Compensation Discussion and Analysis section, the tabular disclosure regarding such compensation, and the accompanying narrative disclosure, set forth in this proxy statement;
- Proposal 4— the approval of an amendment to the Company's amended and restated articles of incorporation to provide holders of at least 25% of the voting power of all outstanding shares entitled to vote the right to call a special meeting of shareholders;
- Proposal 5—the consideration of the shareholder proposal regarding an independent chairman policy as described in this proxy statement, if properly presented at the annual meeting;
- Proposal 6—the consideration of the shareholder proposal regarding the adoption of quantitative goals for reducing greenhouse gas emissions and report on plans to achieve such goals as described in this proxy statement, if properly presented at the annual meeting; and
- such other business as may properly come before the annual meeting or any adjournments.

How does the board recommend I vote on the proposals?

The board of directors recommends you vote "FOR" all nominees listed in proposal 1, "FOR" each of proposals 2, 3 and 4, and "AGAINST" each of proposals 5 and 6.

How do I vote?

Most of our shareholders have three options for submitting their votes;

- By telephone,
- Via the internet, or
- By mail.

If your AGL Resources shares are held in your name on the records maintained by Wells Fargo Bank, N.A., our transfer agent (meaning you are a "shareholder of record"), please follow the instructions on your proxy card.

If your AGL Resources shares are held through a brokerage firm or bank (that is, in "street name"), your ability to vote by telephone or over the internet depends on the voting process of your brokerage firm or bank. Please follow the directions on your vote instruction card.

Regardless of whether your AGL Resources shares are held by you as a record shareholder or in street name, you may attend the meeting and vote your shares in person. Please note that if your shares are held in street name and you want to vote in person, you must bring evidence of your stock ownership, such as a proxy obtained from your street name nominee (particularly if you want to vote your shares at the annual meeting) or your most recent brokerage account statement (in which case you will not be able to vote your shares at the meeting), together with valid picture identification.

Even if you plan to attend the meeting, we encourage you to vote your shares by telephone, internet or mail to simplify the voting process at the meeting.

How do I vote if my shares are held in one of the 401(k) plans?

If your AGL Resources shares are held in one of the 401(k) plans, only the plan trustee can vote your plan shares even if you attend the annual meeting in person. The plan trustee will vote your shares in accordance with your telephone, internet or written proxy vote. Please follow the instructions on your proxy card.

May I revoke my proxy?

Yes. You may revoke your proxy or vote instructions at any time before the annual meeting by voting again by telephone or via the internet or by timely signing and returning another proxy or vote instruction card with a later date. Additionally, if you are a shareholder of record or if you are a street name holder who has obtained a vote instruction card from your street name nominee, and you decide to attend the meeting and vote in person, you may request that any proxy or vote instruction card that you previously submitted not be used.

What if I don't specify my choices when returning my proxy or vote instruction card?

If you return a signed and dated proxy or vote instruction card without indicating your vote, your shares will be voted "FOR" all nominees listed in proposal 1, "FOR" each of proposals 2, 3 and 4, and "AGAINST" each of proposals 5 and 6 and in the discretion of the proxies on any other matter that may properly come before the meeting.

If you hold AGL Resources shares through one of our 401(k) plans and you return the proxy card but do not properly sign or date it or specify how you want your plan shares voted, it is expected that (i) in the case of the AGL 401(k) Plan, the plan trustee, upon instruction from the Administrative Committee of the AGL 401(k) Plan, will vote your plan shares "FOR" all nominees listed in proposal 1, "FOR" each of proposals 2, 3 and 4, and "AGAINST" each of proposals 5 and 6, and as instructed by the Administrative Committee on any other proposals that may properly come before the meeting and (ii) in the case of the Nicor Gas Thrift Plan, the plan trustee will vote your plan shares in the same proportion that other participants in the plan have voted their shares.

May my shares be voted if I don't submit a proxy or voting instructions?

If your AGL Resources shares are registered in your name on the books kept by our transfer agent and you do not return a signed proxy and do not vote by telephone or via the internet or in person at the meeting, your shares will not be voted.

If your AGL Resources shares are held in street name and you do not submit any voting instructions, your brokerage firm or bank may or may not vote your shares with regard to each of the six proposals, depending on stock exchange rules. If your AGL Resources shares are held through one of the 401(k) plans and you do not return the proxy card for those plan shares and do not vote by telephone or the internet or in person, it is expected that, in the case of the AGL 401(k) Plan, the plan trustee, upon instruction from the Administrative Committee, will vote your shares "FOR" all nominees listed in proposal 1, "FOR" each of proposals 2, 3 and 4, and "AGAINST" each of proposals 5 and 6, and as instructed by the Administrative Committee on any other proposals that may properly come before the meeting. In the case of the Nicor Gas Thrift Plan, the plan trustee will vote your shares in the same proportion that other participants in the plan have voted their shares.

How many shares may I vote?

As of February 17, 2015, the record date for voting at the annual meeting, 119,792,280 shares of common stock of AGL Resources were outstanding and entitled to be voted at the annual meeting. You are entitled to one vote for each share of AGL Resources common stock you owned on the record date.

Is there a list of shareholders entitled to notice of the annual meeting?

A list of shareholders entitled to notice of the annual meeting will be available at the annual meeting for inspection by any shareholder. A list of shareholders will also be available for inspection by any shareholder during ordinary business hours at our principal place of business at Ten Peachtree Place, Atlanta, Georgia.

How many votes must be present to hold the annual meeting?

A majority of the 119,792,280 shares of AGL Resources' common stock outstanding on the record date and eligible to be voted, must be present, either in person or represented by proxy, to conduct the annual meeting.

How many votes are needed to approve each of the proposals?

The following are the vote requirements for each of the proposals:

- *Election of 15 directors*: In uncontested elections, a director must receive the vote of at least the majority of votes cast with respect to his or her election in order to be elected. Each of the 15 director nominees for whom the votes cast "FOR" election exceed 50% of the number of votes cast with respect to that director's election will be elected as a director.
- *Ratification of the appointment of PricewaterhouseCoopers LLP*: Ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm requires the votes cast "FOR" to exceed the votes cast "AGAINST."
- *Advisory Vote on Executive Compensation*: Adoption of the non-binding resolution to approve executive compensation requires the votes cast "FOR" to exceed the votes cast "AGAINST."
- *Approval of the amendment to the Company's amended and restated articles of incorporation:* Approval of the amendment to the Company's amended and restated articles of incorporation requires the affirmative vote of the majority of shares entitled to vote on the proposal.
- *Shareholder Proposal regarding an Independent Chairman Policy*: Adoption of this shareholder proposal requires the votes cast "FOR" to exceed the votes cast "AGAINST."
- *Shareholder Proposal regarding Goals for Reducing Greenhouse Gas Emissions*: Adoption of this shareholder proposal requires the votes cast "FOR" to exceed the votes cast "AGAINST."

What happens if a director nominee fails to receive a majority of the votes cast in his or her election?

As described under the caption, "Proposal 1—Election of Directors—General—Vote Requirements for Election," our bylaws provide that a director nominee in an uncontested election must receive the affirmative vote of at least the majority of votes cast in order to be elected. If the votes cast "FOR" the director's election do not exceed 50% of the number of votes cast with respect to that director's election, the director must promptly tender his or her resignation to the board of directors following certification of the shareholder vote. The Nominating, Governance and Corporate Responsibility Committee must then recommend to the board of directors whether to accept or reject the tendered resignation or whether to take other action. The board must then act on the tendered resignation and publicly disclose its decision and the rationale behind the decision within 90 days after the certification of the election results.

What if I vote against electing directors?

In voting for the election of directors, a vote "against" one or more director nominees will be counted for quorum purposes. Such a vote also will be counted for purposes of determining whether a director nominee received the affirmative vote of at least the majority of votes cast in order to be elected. Please see "What happens if a director nominee fails to receive a majority of the votes cast in his or her election?" above.

How will abstentions and broker non-votes be treated?

Abstentions and broker non-votes will be treated as shares present and entitled to vote for quorum purposes. Abstentions and broker non-votes will not be treated as "votes cast" and consequently they will not affect the outcome of the vote on the election of directors or the determination of whether a director nominee has received the affirmative vote of the majority of votes cast (Proposal 1), the proposal to ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm (Proposal 2), the proposal to adopt the non-binding resolution to approve the compensation of our named executive officers (Proposal 3), or the shareholder proposals described in this proxy statement (Proposal 5 and Proposal 6). Abstentions or a failure to vote will have the same effect as a vote "AGAINST" the proposal to approve an amendment to the Company's amended and restated articles of incorporation (Proposal 4).

"Broker non-votes" occur on a matter up for vote when a broker, bank or other holder of shares you own in "street name" is not permitted to vote on that particular matter without instructions from you, you do not give such instructions and the broker or other nominee indicates on its proxy card, or otherwise notifies us, that it does not have authority to vote its shares on that matter.

Whether a broker has authority to vote its shares on uninstructed matters is determined by stock exchange rules.

Could other matters be decided at the annual meeting?

We do not know of any other matters that will be considered at the annual meeting. If a matter that is not listed on the proxy or vote instruction card is properly brought before the annual meeting in accordance with Section 1.2 of our bylaws, the persons named as proxies will vote in accordance with their judgment of what is in the best interest of the Company, based on the discretionary voting authority conferred on them by the proxy and vote instruction cards.

Who will count the votes?

Representatives of Broadridge Financial Solutions, Inc. will count the votes and act as inspector of elections.

Where and when will I be able to find the voting results?

We will post the voting results on our website at *www.aglresources.com* within four business days after the annual meeting. You also will find the results in a Current Report on Form 8-K, which we expect to file with the SEC within four business days following the annual meeting.

What does it mean if I receive more than one proxy card?

It means that you have multiple accounts with brokerage firms, banks and/or our transfer agent. Please vote all of these shares. We recommend that you contact your broker, bank and/or our transfer agent to consolidate as many accounts as possible under the same name and address. All communications concerning accounts for shares registered in your name on the books kept by our transfer agent, including address changes, name changes, inquiries to transfer shares and similar issues, may be handled by making a toll-free call to Wells Fargo Shareowner Services at (800) 468-9716.

What do I need to bring with me if I want to attend the annual meeting?

The annual meeting is open to all holders of our common stock. To attend the annual meeting, you will need to bring an admission ticket and valid picture identification. If your shares are registered in your name on the books kept by our transfer agent or your shares are held in one of the 401(k) plans, your admission ticket is part of your proxy card or may be printed from the internet when you vote online.

If your shares are held in street name by your brokerage firm or bank, you will need to bring evidence of your stock ownership, such as a proxy obtained from your street name nominee (particularly if you want to vote your shares at the annual meeting) or your most recent brokerage account statement (in which case you will not be able to vote your shares at the annual meeting), together with valid picture identification. You also may request that we send you an admission ticket. If you do not have either an admission ticket or proof that you own our common stock, together with valid picture identification, you may not be admitted to the meeting.

What happens if the annual meeting is postponed or adjourned?

Your proxy will still be valid and may be voted at a postponed or adjourned meeting, unless the board of directors fixes a new record date for the postponed or adjourned meeting, which the board is required to do if the postponement or adjournment is for more than 120 days. If the meeting is postponed or adjourned, you will still be able to change or revoke your proxy until it is voted.

When are shareholder proposals for the 2016 annual meeting due?

Our bylaws require shareholders to give us advance notice of any shareholder nominations of directors and of any other matters shareholders wish to present for action at an annual meeting of shareholders. The required notice must be given within a prescribed time frame, which is calculated by reference to the date that the proxy statement was released to shareholders in connection with our most recent annual meeting. Accordingly, with respect to our 2016 annual meeting of shareholders, our bylaws require notice to be provided to our Corporate Secretary at AGL Resources Inc., P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569 no later than November 18, 2015. However, if the 2016 annual meeting of shareholders is held on a date more than 30 days from the date contemplated at the time of this proxy statement, our bylaws require notice to be provided to our Corporate Secretary at the address above not fewer than the later of (i) 150 days prior to the date of the 2016 annual meeting of shareholders or (ii) the date which is ten days after the date of the first public announcement or other notification to shareholders of the date of the 2016 annual meeting of shareholders.

If you are interested in submitting a proposal for inclusion in our proxy statement for the 2016 annual meeting of shareholders, you need to follow the procedures outlined in the SEC’s Rule 14a-8. To be eligible for inclusion, your shareholder proposal intended for inclusion in the proxy statement for the 2016 annual meeting of shareholders must be received no later than November 18, 2015, by our Corporate Secretary at the address above.

This deadline does not apply to questions a shareholder may wish to ask at the annual meeting.

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Who pays the costs associated with this proxy solicitation?

AGL Resources pays the expenses of soliciting proxies. We have hired Alliance Advisors LLC to assist in the solicitation of proxies. Alliance Advisors LLC may solicit proxies in person or by telephone, facsimile or electronic transmission. We will pay Alliance Advisors LLC approximately $11,500 plus customary costs and expenses for these services. Additionally, proxies may be solicited on our behalf by directors, officers and employees, in person or by telephone, facsimile or electronic transmission. Directors, officers and employees will not be paid additional fees for those services.

CORPORATE GOVERNANCE

Board of Directors

Our business affairs are managed under the direction of the board of directors in accordance with the Georgia Business Corporation Code, our amended and restated articles of incorporation and our bylaws. The role of the board of directors is to govern our affairs for the benefit of our shareholders and other constituencies, which include our employees, customers, suppliers, creditors and the communities in which we do business. The board strives to ensure the success and continuity of our business through the appointment of qualified executive management, overseen by the board.

Director Independence

Pursuant to New York Stock Exchange listing standards, our board of directors has adopted a formal set of categorical Standards for Determining Director Independence (the “Standards”). In accordance with these Standards, a director must be determined to have no material relationship with the Company other than as a director in order to be considered an independent director. The Standards specify the criteria by which the independence of our directors will be determined, including strict guidelines for directors and their immediate family members with respect to past employment or affiliation with the Company or its independent registered public accounting firm. The Standards also set forth independence criteria applicable to members of the Audit Committee, the Compensation Committee and the Nominating, Governance and Corporate Responsibility Committee of the board of directors. These Standards are available on our website at *www.aglresources.com*.

In accordance with these Standards, the board undertook in February 2015 an annual review of director independence. Based on this review, the board has affirmatively determined that, as to each current non-employee director, no material relationship exists that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director and that each current non-employee director qualifies as “independent” in accordance with the Standards and the independence standards of the New York Stock Exchange.

John W. Somerhalder II, our chairman, president and chief executive officer, is not independent because of his employment by the Company. Mr. Somerhalder will not participate in any action of the board related to his compensation or any other matters requiring action by only non-employee directors.

In making these independence determinations, the board considered that in the ordinary course of business, transactions may occur between the Company and its subsidiaries and companies at which some of our directors are or have been directors, officers or employees. The board also considered that the Company and its subsidiaries may make charitable contributions to not-for-profit organizations where our directors or their immediate family members serve or are executive officers.

Policy on Related Person Transactions

The board of directors recognizes that related person transactions present a heightened risk of conflicts of interest and, therefore, has adopted a written policy with respect to related person transactions. For the purpose of the policy, “Related Persons” include (a) each executive officer as defined under Section 16 of the Securities Exchange Act of 1934, as amended, or the “Exchange Act,” (b) each executive and senior vice president of AGL Resources, (c) each nominee for or member of the board of directors, (d) each holder of more than 5% of our common stock, or a “Significant Shareholder,” and (e) any immediate family member, as defined under the Exchange Act, of the persons listed in (a) through (d) above. A “Related Person Transaction” is a transaction between us and any Related Person, other than (1) transactions available to all employees or customers generally; (2) transactions involving less than $120,000 when aggregated with all similar transactions since January 1, 2014; (3) transactions excluded from disclosure in paragraphs four through seven of the instructions to Item 404(a) of Regulation S-K under the Exchange Act; and (4) charitable contributions by the Company to a charitable organization with which a Related Person’s only relationship is as an employee (other than an executive officer), if the aggregate amount involved does not exceed the greater of $1,000,000 or 2% of the charitable organization’s annual receipts for the preceding fiscal year.

Under the policy, when management becomes aware of a Related Person Transaction involving a dollar amount that is less than two percent of either the Company’s consolidated gross revenues or the consolidated gross revenues of the Related Person, or any affiliate of such Related Person, for the prior fiscal year, management reports the transaction to the Chairman of the Nominating, Governance and Corporate Responsibility Committee. When management becomes aware of a Related Person Transaction involving a dollar amount that is equal to or exceeds two percent of either the Company’s consolidated gross revenues or the consolidated gross revenues of the Related Person, or any affiliate of such Related Person, for the prior fiscal year, management reports the transaction to the Nominating, Governance and Corporate Responsibility Committee and requests approval or ratification of the transaction.

Transactions requiring approval or ratification must be approved by a majority of the disinterested members of the Nominating, Governance and Corporate Responsibility Committee. The Chairman will report to the full Nominating, Governance and Corporate Responsibility Committee at its next regularly scheduled committee meeting any Related Person Transactions that are presented to him or her. The Nominating, Governance and Corporate Responsibility Committee will report to the full board all Related Person Transactions presented to it.

Board Leadership Structure

Our Company is led by Mr. John Somerhalder, who has served as our president and chief executive officer since March 2006 and our chairman, president and chief executive officer since October 2007. In 2014, our board of directors consisted of Mr. Somerhalder and 14 independent directors. Each of the standing committees of our board of directors is chaired by an independent director and each of our Audit, Compensation and Nominating, Governance and Corporate Responsibility committees is comprised entirely of independent directors.

Under our Guidelines on Significant Corporate Governance Issues, or our Corporate Governance Guidelines, a copy of which is available on our website at *www.aglresources.com*, if the chairman of the board of directors is an executive officer or employee of the Company, then the board of directors shall appoint, from among the independent directors, a lead director. Mr. Arthur E. Johnson currently serves as our Lead Director.

The board of directors appoints the Lead Director for a term ending on the earlier of (a) three years from the date of appointment or (b) the last day of the individual’s service on the board of directors. The Lead Director: (a) serves as chairman of the Executive Committee of the board of directors; (b) presides at the executive sessions of non-management directors; (c) collaborates with our chairman, president and chief executive officer, our general counsel and our corporate secretary on setting the annual calendar and agendas for all regular meetings of the board and its standing committees; (d) maintains close contact with the chairperson of each standing committee; (e) oversees the Company's policy on communications between shareholders or other interested parties and non-management directors; and (f) in conjunction with the chairperson of the Compensation Committee, communicates the results of the annual evaluation of the chief executive officer to the chief executive officer on behalf of the board of directors.

We have determined that our current board leadership structure is appropriate and helps ensure both effective and efficient governance for the Company, for a number of reasons, the most significant of which are the following:

- A combined chairman and chief executive officer role allows for more productive meetings. The chief executive officer is the individual selected by the board of directors to manage the Company on a day to day basis, and his direct involvement in the Company's operations makes him best positioned to lead productive board strategic planning sessions and determine the time allocated to each agenda item in discussions of the Company's short- and long-term objectives.
- Our board structure provides strong oversight by independent directors and in addition a majority of our operations are subject to extensive regulation. In fact, our chief executive officer is the only one of our current 15 directors who is not independent. Our Lead Director's responsibilities include leading executive sessions of the board of directors during which our independent directors meet without management. These executive sessions allow the board of directors to review key decisions and discuss matters in a manner that is independent of the chief executive officer, and where necessary, critical of the chief executive officer and senior management. In addition, each of our board's standing committees is chaired by an independent director.
- Recognizing there may be a circumstance where a shareholder or other interested party's interest should be represented independent of management, a key responsibility of the Lead Director is to receive, review and, where necessary, act upon direct communications from shareholders and other interested parties.

If you wish to communicate directly with (i) the board of directors generally, (ii) the presiding director of executive sessions of non-management directors (our Lead Director), or (iii) non-management directors as a group, you should contact the Company's Ethics and Compliance Helpline at (800) 350-1014 or at *www.mycompliancereport.com* using the access ID, "AGL." Calls to the helpline and reports made via the website, if you choose, can be made anonymously.

The Board's Role in Risk Oversight

The board oversees the Company's risk assessment and risk management processes. It does so in part through the committees of the board. Our Audit Committee has the responsibility to review with management the Company's (i) policies governing the process by which risk assessment and risk management are undertaken; and (ii) major financial risk exposures and the steps management has taken to monitor and control such exposures. Our Finance and Risk Management Committee has the responsibility to (i) review with management the steps taken by management to ensure compliance with the Company's risk management policies and procedures relating to interest rate risk, currency risk, credit risk, commodity risk and derivatives related to any of the foregoing; (ii) review steps taken by management to establish and monitor trading and risk management systems and controls at the Company's asset management and optimization businesses and to ensure compliance at such businesses with risk management policies and procedures applicable to such businesses; and (iii) review management's assessment of controls and procedures associated with such businesses' management of transactions with affiliates and any reporting obligations to state or federal regulatory authorities. Our chief risk officer provides a quarterly report to the Finance and Risk Management Committee and meets in executive sessions with the Finance and Risk Management Committee at each regularly scheduled meeting. Each of the other committees of the board of directors has principal responsibility for reviewing and discussing with management those risk exposures: (i) specified in their charters or (ii) identified from time to time by the committees themselves or by the Audit Committee.

In addition, the board authorized the formation of the Company's Risk Management Committee (RMC), a committee of certain members of senior management. The RMC is responsible for establishing specific risk management policies and monitoring compliance with, and adherence to, the terms of these policies. Members of the RMC are members of senior management who monitor natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. The RMC is chaired by the Company's chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions.

The Company conducts an annual enterprise risk assessment, overseen by a sub-committee of the RMC. The purpose of the assessment includes identifying and rating the management of all of the Company's significant risk exposures. The RMC uses the results of this assessment to prioritize the goals of the Company's risk management program and monitor the Company's major risks. Management reports to the board of directors any new risks identified since the previous year's assessment.

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Committees of the Board

The board of directors has established five standing committees to assist it in discharging its duties. Actions taken by any committee of the board are reported to the board, usually at the board meeting next following a committee meeting. Each standing committee has adopted a written charter, which is available on our website at *www.aglresources.com* and is available upon request to our Corporate Secretary at AGL Resources Inc., P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569. The committees of the board and their members at December 31, 2014 are as shown in the following table.

Members of the Board's Committees

	Audit	Compensation	Executive	Finance and Risk Management	Nominating, Governance and Corporate Responsibility
Sandra N. Bane	□	□			
Thomas D. Bell, Jr.		□		□	
Norman R. Bobins	□	□			
Charles R. Crisp		□		□	
Brenda J. Gaines	□				□
Arthur E. Johnson**			□*	□	□
Wyck A. Knox, Jr.	□				□
Dennis M. Love	□		□		□*
Dean R. O'Hare	□				□
Armando J. Olivera		□		□	
John E. Rau			□	□	□
James A. Rubright		□	□	□*	
John W. Somerhalder II			□	□	
Bettina M. Whyte		□*	□	□	
Henry C. Wolf	□*	□	□		

* Denotes committee chair.
** Denotes Lead Director.

Audit Committee

The Audit Committee met 12 times during 2014. All members of the Audit Committee are independent, non-employee directors, as defined under the listing standards of the New York Stock Exchange and our Standards. The Audit Committee's primary function is to assist the board of directors in fulfilling its oversight responsibilities. Among other things, the Audit Committee reviews (1) the integrity of our financial statements, including our internal control over financial reporting, (2) our compliance with legal and regulatory requirements, (3) the independent registered public accounting firm's qualifications and independence, (4) the performance of our internal audit function, and (5) the performance of the independent registered public accounting firm. Our chief financial officer, chief ethics and compliance officer, chief audit executive, chief accounting officer and representatives of our independent registered public accounting firm each provide a quarterly report to and meet in separate executive sessions with the Audit Committee each quarter.

The board of directors has determined that all members of the Audit Committee satisfy the enhanced independence standards applicable to all members of the Audit Committee under the independence requirements of the SEC, the New York Stock Exchange and the Company's Standards for Determining Director Independence. The board also has determined that all members of the Audit Committee meet the financial literacy requirements of the New York Stock Exchange listing standards. The board has further determined that Henry C. Wolf, the Audit Committee Chair, is an "audit committee financial expert" within the meaning of SEC regulations. Information regarding Mr. Wolf's qualification as an "audit committee financial expert" is included in his biographical information under the caption, "Proposal 1—Election of Directors."

Additional information regarding the Audit Committee and its functions and responsibilities is included in this proxy statement under the captions "Audit Committee Report" and "Proposal 2—Ratification of the Appointment of PricewaterhouseCoopers LLP as our Independent Registered Public Accounting Firm for 2015."

Compensation Committee

The Compensation Committee met six times during 2014. All members of the Compensation Committee are independent, non-employee directors, as defined under the listing standards of the New York Stock Exchange and our Standards for Determining Director Independence. Among other things, the Compensation Committee assists the board of directors in its efforts to achieve its goal of maximizing the long-term total return to shareholders by establishing policies by which officers, directors and employees are to be compensated in accordance with the board's compensation philosophy and objectives and by overseeing management succession and executive development processes.

The board of directors delegated to the Compensation Committee the following areas of responsibility that are more fully described in the Compensation Committee's charter: (1) evaluation of the chief executive officer, (2) succession and development planning for executive officers, (3) compensation of non-employee members of the board of directors, (4) compensation of the executive officers, including salary, short- and long-term incentives, and employment or severance arrangements, (5) establishment of performance objectives for executive officers under the Company's short- and long-term incentive compensation plans and determination of the attainment of such performance objectives, and (6) oversight of benefit plans and administration of long-term incentive plans.

The Compensation Committee has delegated to our chief executive officer the authority to grant equity awards to employees of the Company solely in connection with non-annual grants to employees other than executive officers. The Compensation Committee has established narrowly defined, pre-approved parameters regarding the terms and conditions of grants under the delegated authority, including the eligible employee groups, the maximum number of shares subject to the delegation, the determination of the exercise price and other terms and conditions of the awards. In January 2014, the Compensation Committee adopted a policy on granting equity compensation awards that provides additional terms and conditions for making grants. See "Compensation Discussion and Analysis—Other Policies Governing our Executive Compensation Program—Grants of Long-Term Incentive Awards" for more detail concerning our grant policy.

Our chief executive officer, based on the performance evaluations of the other executive officers, recommends to the Compensation Committee compensation for those executive officers. The executive officers, including our chief executive officer, also provide recommendations to the Compensation Committee from time to time related to compensation philosophy, program design, compliance, performance measures and competitive strategy.

The Compensation Committee's charter provides that the Compensation Committee, in its sole discretion, has the authority to retain compensation consultants. Accordingly, Frederic W. Cook & Co., Inc. ("F.W. Cook"), was retained directly by the Compensation Committee to assist it in 2014. F.W. Cook's role is to provide expertise and data as needed by the Compensation Committee pertaining to all aspects of executive and director compensation, including but not limited to advice and counsel as to the amount and form of executive and director compensation, and to advise the Compensation Committee on emerging trends, best practices and regulatory practices.

The Compensation Committee evaluated the independence of F.W. Cook in light of new SEC rules and New York Stock Exchange listing standards, which require consideration of the following factors:

- whether any other services are provided to the Company by the consultant;
- the fees paid by the Company as a percentage of the consulting firm's total revenue;
- the policies or procedures maintained by the consulting firm that are designed to prevent a conflict of interest;
- any business or personal relationships between the individual consultants involved in the engagement and a member of the Compensation Committee;
- any company stock owned by the individual consultants involved in the engagement; and
- any business or personal relationships between our executive officers and the consulting firm or the individual consultants involved in the engagement.

The Compensation Committee discussed these considerations and concluded that the engagement of F.W. Cook and the services provided to the Compensation Committee by F.W. Cook did not raise any conflict of interest.

Executive Committee

The Executive Committee met two times during 2014. The Executive Committee may meet during intervals between board meetings and has the same authority as the full board of directors, subject to limitations imposed by law or our bylaws.

Finance and Risk Management Committee

The Finance and Risk Management Committee met five times during 2014. The Finance and Risk Management Committee's primary function is to assist the board of directors in fulfilling its oversight responsibilities. Among other things, the Finance and Risk Management Committee oversees (1) the management of our balance sheet including leverage, liquidity, funding sources and related matters, (2) the annual capital budget and certain capital projects, (3) management's assessments, actions, processes and procedures concerning our exposure to risks identified in the Finance and Risk Management Committee's charter, and (4) any other matters that the board may delegate to the Finance and Risk Management Committee from time to time. Our chief risk officer provides a quarterly report to and meets in executive session with the Finance and Risk Management Committee at each regularly scheduled meeting.

Nominating, Governance and Corporate Responsibility Committee

The Nominating, Governance and Corporate Responsibility Committee met five times during 2014. All members of the Nominating, Governance and Corporate Responsibility Committee are independent, non-employee directors, as defined under the listing standards of the New York Stock Exchange and our Standards for Determining Director Independence. The Nominating, Governance and Corporate Responsibility Committee's primary responsibilities include (1) identifying individuals qualified to serve on the board of directors and recommending director nominees for selection by the full board of directors or shareholders, (2) evaluating, formulating and recommending to the board of directors corporate governance policies, and (3) overseeing the Company's position on corporate, social and environmental responsibilities.

Nomination of Director Candidates. The board of directors is responsible for recommending director candidates for election by the shareholders and for electing directors to fill vacancies or newly created directorships. The board of directors has delegated the screening and evaluation process for director candidates to the Nominating, Governance and Corporate Responsibility Committee, which identifies, evaluates and recruits highly qualified director candidates and recommends them to the board of directors. Potential candidates for director may come to the attention of the Nominating, Governance and Corporate Responsibility Committee through current directors, management, professional search firms, shareholders or other persons.

If the Nominating, Governance and Corporate Responsibility Committee has either identified a prospective nominee or determined that an additional or replacement director is required, the Nominating, Governance and Corporate Responsibility Committee may take such measures that it considers appropriate in connection with its evaluation of a director candidate, including candidate interviews, engagement of an outside firm to gather additional information and inquiry of persons with knowledge of the candidate's qualifications and character. In its evaluation of director candidates, including the members of the board of directors eligible for reelection, the Nominating, Governance and Corporate Responsibility Committee considers the current size and composition of the board of directors and the needs of the board of directors and the respective committees of the board in view of the criteria for directors described in our Corporate Governance Guidelines, a copy of which is available on our website at *www.aglresources.com.*

The Nominating, Governance and Corporate Responsibility Committee will consider director nominees proposed by shareholders. A shareholder may recommend a person for nomination for election to our board of directors by writing to our Corporate Secretary at AGL Resources Inc., P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569. Pursuant to our Corporate Governance Guidelines, each submission must include:

- A brief biographical description of the candidate, including background and experience;
- The candidate's name, age, business address, and residence address;
- The candidate's principal occupation;
- The following information about the shareholder making the recommendation:
  - the name and record address of such shareholder;
  - the number of shares of our common stock owned beneficially or of record by such shareholder;
  - a description of all arrangements or undertakings between such shareholder and each proposed

nominee and any other person or persons (including their names) pursuant to which the nominations are to be made by such shareholder; and

- The written consent of the candidate to being named as a nominee and to serve as a director if elected.

A shareholder's recommendation for a candidate for nomination to be elected at the next annual meeting of shareholders must be received by our Corporate Secretary no later than 45 days prior to the end of the year preceding such annual meeting of shareholders. The Nominating, Governance and Corporate Responsibility Committee will evaluate these recommendations in the same manner as it evaluates all other nominees, using the criteria described in our Corporate Governance Guidelines.

The Nominating, Governance and Corporate Responsibility Committee periodically engages a third party search firm to identify possible director candidates for the Nominating, Governance and Corporate Responsibility Committee's consideration based on skills and characteristics identified by the Nominating, Governance and Corporate Responsibility Committee and in light of gaps in board composition that the Nominating, Governance and Corporate Responsibility Committee may identify from time to time as the issues facing the board evolve. Such skills and characteristics desirable in the context of the then current make-up of the board of directors may include diversity, age, business or professional background, financial literacy and expertise, availability, commitment, independence and other relevant criteria.

Practices for Considering Diversity. The charter of the Nominating, Governance and Corporate Responsibility Committee provides that it shall review, at least annually, the appropriate skills and characteristics of members of the board of directors in the context of the then current make-up of the board. This assessment includes the following factors: geographic representation (representative of our service territories); diversity of professional skills and experience; diversity of age, gender and race; energy industry experience; community relations within our service territories; and other criteria that the Nominating, Governance and Corporate Responsibility Committee or the full board determines to be relevant. It is the practice of the Nominating, Governance and Corporate Responsibility Committee to consider these factors when screening and evaluating candidates for nomination to the board of directors.

Board and Committee Meetings

Members of the board are kept informed through reports routinely presented at board and committee meetings by our chief executive officer and other company leaders and through other means. During 2014, the board of directors held eight meetings. Each director attended 75% or more of the aggregate of all meetings of the board and each committee on which he or she served.

Executive Sessions without Management

To promote open discussion among the non-management directors, the board of directors schedules regular executive sessions in which the non-management directors meet without management's participation. Such sessions are scheduled to occur at every regularly scheduled board meeting. The presiding director at such executive sessions is the Lead Director and Chairman of the Executive Committee of the board of directors. During 2014, the board met in executive session five times.

Communications with Directors

Shareholders and other interested parties may communicate with our board of directors or, alternatively, with the presiding director of executive sessions of our non-management directors or with the non-management directors as a group via our Ethics and Compliance Helpline at (800) 350-1014 or at *www.mycompliancereport.com*. A copy of our Procedures for Communicating with the Board of Directors of AGL Resources Inc. is available on our website at *www.aglresources.com* and is available in print to any shareholder who requests it from our Corporate Secretary at AGL Resources Inc., P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569.

Ethics and Compliance Program

The board of directors is responsible for overseeing management's implementation of the Company's ethics and compliance program to ensure that our business is conducted in a consistently legal and ethical manner. As part of the ethics and compliance program, our Company has established, and the board of directors has approved, our Code of Conduct and Ethics. Our Code of Conduct and Ethics governs the way we treat our customers and co-workers, guides our community interactions, and strengthens our commitment to excellence and integrity. The Code of Conduct and Ethics covers a wide range of professional conduct, including environmental, health and safety standards, employment policies, conflicts of interest, accuracy of records, fair dealing, insider trading and strict adherence to all laws and regulations applicable to the conduct of our business. Under the Code of Conduct and Ethics, employees are required to conduct the Company's activities in an ethical and lawful manner and all employees are expected to report any situation where they believe our internal policies or external laws are being violated. Our Code of Conduct and Ethics applies to our directors, officers and all of our employees.

In addition, the board of directors has adopted a Code of Ethics for the Chief Executive Officer and the Senior Financial Officers, or our Officers Code of Ethics, designed to deter wrongdoing and promote the following: honest and ethical conduct; full, fair, accurate, timely and understandable disclosure in documents filed with or submitted to the SEC; compliance with applicable governmental laws, rules and regulations; prompt internal reporting of violations of the Officers Code of Ethics; and accountability for adherence to the Officers Code of Ethics.

Any waiver of the Code of Conduct and Ethics or Officers Code of Ethics for an executive officer or, where applicable, for a member of the board of directors, requires the approval of the board of directors or a duly authorized committee of the board and will be promptly disclosed on our website at *www.aglresources.com*. No waivers have been granted under the codes.

The board of directors also has adopted Guidelines on Significant Corporate Governance Issues, or our Corporate Governance Guidelines, that set forth guidelines for the operation of the board of directors and its committees. The board periodically reviews our governance practices and procedures, evaluating them against corporate governance best practices.

Our Code of Conduct and Ethics, our Officers Code of Ethics and our Corporate Governance Guidelines are available on our website at *www.aglresources.com.* They also are available to any shareholder upon request to our Corporate Secretary at AGL Resources Inc. at P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Directors and Executive Officers

The following table presents the number of shares of AGL Resources common stock beneficially owned by each director, each named executive officer and by all executive officers and directors as a group as of December 31, 2014, based on information furnished by them to us. Our named executive officers are those individuals named in the Summary Compensation Table under the caption “Executive Compensation.”

Beneficial ownership as reported in the table below has been determined in accordance with SEC regulations and includes shares of common stock which may be acquired within 60 days after December 31, 2014, upon the exercise of outstanding stock options but excludes shares and share equivalents held under deferral plans which are disclosed in a separate column. Unless otherwise indicated, all directors and executive officers have sole voting and investment power with respect to the shares shown. As of December 31, 2014, no individual director or named executive officer beneficially owned 1% or more of our common stock. Our executive officers and directors as a group beneficially owned approximately 1% of our common stock.

	Shares of Common Stock Beneficially Owned			
Name	Owned Shares	Option Shares(1)	Shares and Share Equivalents Held Under Deferral Plans(2)	Total
Sandra N. Bane	3,410	0	14,621	18,031
Thomas D. Bell, Jr.	30,465	0	0	30,465
Norman R. Bobins(3)	10,494	0	0	10,494
Charles R. Crisp	14,668	0	14,056	28,724
Brenda J. Gaines	10,082	0	0	10,082
Arthur E. Johnson	4,338	0	48,161	52,499
Wyck A. Knox, Jr.	12,122	0	46,400	58,522
Dennis M. Love	36,600	0	40,630	77,230
Dean R. O’Hare	20,501	0	897	21,398
Armando J. Olivera	1,875	0	11,889	13,764
John E. Rau(4)	20,840	0	0	20,840
James A. Rubright	19,469	0	25,272	44,741
John W. Somerhalder II(5)	143,909	384,400	45,218	573,527
Bettina M. Whyte	14,506	0	17,991	32,497
Henry C. Wolf	30,863	0	12,823	43,686
Andrew W. Evans	66,738	0	0	66,738
Henry P. Linginfelter	78,901	0	43	78,944
Paul R. Shlanta	32,391	20,540	0	52,931
Peter I. Tumminello	39,471	12,870	0	52,341
All executive officers and directors as a group (20 persons)(6)	626,071	417,810	278,001	1,321,882

(1) Reflects the shares that may be acquired upon exercise of stock options granted under the AGL Resources Inc. Omnibus Performance Incentive Plan, as Amended and Restated (which we refer to as the OPIP), the Long-Term Incentive Plan (1999) (which we refer to as the Long-Term Incentive Plan) and which was the predecessor plan to the OPIP, or under the Officer Incentive Plan.

(2) Represents shares of common stock, common stock equivalents and accrued dividend credits held for non-employee directors under the 1998 Common Stock Equivalent Plan for Non-Employee Directors, which we refer to as the Common Stock Equivalent Plan, and, for the named executive officers, under the Nonqualified Savings Plan. The common stock equivalents track the performance of AGL Resources common stock and are payable in cash. The shares and share equivalents may not be voted or transferred by the participants.

(3) Includes 502 shares held in a trust for which Mr. Bobins has sole voting and investment power with respect to the shares.

(4) Includes 4,610 shares held in a trust for which Mr. Rau has sole voting and investment power with respect to the shares.

(5) Includes 69,711 shares held in a trust for which Mr. Somerhalder has sole voting and investment power with respect to the shares.

(6) Includes 34,428 shares for which a member of the group who is not a named executive officer has shared voting and investment power.

Owners of More Than 5% of AGL Resources Common Stock

We are aware of the following shareholders who beneficially own more than 5% of AGL Resources common stock.

Name and Address of Beneficial Owner	Shares of Common Stock Beneficially Owned	Percent of Class
BlackRock, Inc. 55 East 52nd Street New York, NY 10022	9,515,698(1)	8.0%
The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	9,551,741(2)	8.0%

(1) Based on the Schedule 13G/A filed with the SEC on January 23, 2015, in which BlackRock, Inc. reported that it holds all of its shares as a parent holding company or control person in accordance with Rule 13d-1(b)(1)(ii)(G) of the Exchange Act and has sole voting power with respect to 8,714,732 of its shares and sole dispositive power with respect to all of its shares.

(2) Based on the Schedule 13G/A filed with the SEC on February 11, 2015, in which The Vanguard Group, Inc. (“Vanguard”) reported that it holds all of its shares as an investment advisor in accordance with Rule 13d-1(b)(1)(ii)(E) of the Exchange Act and has sole voting power of 177,858 of the total shares, sole dispositive power of 9,392,033 of the total shares and shared dispositive power of 159,708 of the total shares.

Based on the Schedule 13G/A, (i) Vanguard Fiduciary Trust Company (“VFTC”), a wholly-owned subsidiary of Vanguard, is the beneficial owner of 159,708 shares or 0.13% of the common stock outstanding of the Company as a result of its serving as investment manager of collective trust accounts, and as such, VFTC directs the voting of these 159,708 shares; and (ii) Vanguard Investments Australia, Ltd. (“VIA”), a wholly-owned subsidiary of Vanguard, is the beneficial owner of 18,150 shares or 0.01% of the common stock outstanding of the Company as a result of its serving as investment manager of Australian investment offerings, and as such, VIA directs the voting of these 18,150 shares.

DIRECTOR COMPENSATION

General

A director who is an employee of the Company receives no additional compensation for his or her services as a director. A director who is not an employee (a non-employee director) receives compensation for his or her services as described in the following paragraphs. All directors are reimbursed for reasonable expenses incurred in connection with attendance at board and committee meetings.

Annual Retainer

Each non-employee director receives an annual retainer for service as a director on the first day of each annual service term. The amount and form of the annual retainer are fixed from time to time by resolution of the board. For 2014, the annual retainer was $190,000, of which $95,000, or the Cash Portion, was payable in cash and $95,000, or the Equity Portion, was payable in shares of our common stock on the first day of the annual service term. Alternatively, a director may choose to receive his or her entire retainer (including the Cash Portion) in shares of our common stock, or to defer the retainer under the Common Stock Equivalent Plan.

Amounts deferred under the Common Stock Equivalent Plan are invested in common stock equivalents that track the performance of our common stock and are credited with equivalents to dividend payments that are made on our common stock. Common stock equivalents may not be voted or transferred. At the end of a participating non-employee director’s board service, he or she receives a cash distribution based on the then-current market value of his or her common stock equivalents and dividend equivalents.

Non-employee directors do not receive additional compensation for attending board or committee meetings.

Committee Chair and Lead Director Retainer

Committee chairs receive an additional annual retainer on the first day of each annual service term. For 2014, the additional annual retainer for each committee chair was $15,000 and the additional annual retainer for the Lead Director was $25,000. The committee chair and Lead Director retainers were payable, at the election of each director, in cash or shares of our common stock, or they were deferred under the Common Stock Equivalent Plan.

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2014 Non-Employee Director Compensation Paid

The following table summarizes compensation earned and paid to or deferred by each non-employee director for service as a director during 2014.

2014 Non-Employee Director Compensation

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)(2)	All Other Compensation ($)	Total ($)
Sandra N. Bane	95,000	95,000	—	190,000
Thomas D. Bell, Jr.	95,000	95,028	—	190,028
Norman R. Bobins	95,000	95,028	—	190,028
Charles R. Crisp	95,000	95,028	—	190,028
Brenda J. Gaines	95,000	95,028	—	190,028
Arthur E. Johnson	135,000	95,000	—	230,000
Wyck A. Knox, Jr.	95,000	95,000	—	190,000
Dennis M. Love	0	205,015	—	205,015
Charles H. McTier	220,979	0	—	220,979
Dean R. O’Hare	95,000	95,028	—	190,028
Armando J. Olivera	71,250	95,000	—	166,250
John E. Rau	0	190,003	—	190,003
James A. Rubright	110,000	95,028	—	205,028
Bettina M. Whyte	90,000	115,000	—	205,000
Henry C. Wolf	5,000	200,015	—	205,015

(1) The following table presents the grant date fair value for each stock award, which includes shares of our common stock and common stock equivalents, made to each non-employee director during 2014.

Name	Type of Stock Award	Total Grant Date Fair Value ($)
Sandra N. Bane	Common Stock Equivalent	95,000
Thomas D. Bell, Jr.	Common Stock	95,028
Norman R. Bobins	Common Stock	95,028
Charles R. Crisp	Common Stock	95,028
Brenda J. Gaines	Common Stock	95,028
Arthur E. Johnson	Common Stock Equivalent	95,000
Wyck A. Knox, Jr.	Common Stock Equivalent	95,000
Dennis M. Love	Common Stock	200,015
Charles H. McTier	N/A	0
Dean R. O’Hare	Common Stock	95,028
Armando J. Olivera	Common Stock Equivalent	95,000
John E. Rau	Common Stock	190,003
James A. Rubright	Common Stock	95,028
Bettina M. Whyte	Common Stock Equivalent	115,000
Henry C. Wolf	Common Stock	200,015

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(2) The aggregate number of stock awards, which includes shares of our common stock and common stock equivalents, for each of the non-employee directors outstanding at December 31, 2014, was as follows:

Name	Shares Outstanding (#)	Common Stock Equivalents Outstanding (#)(a)	Total Stock Awards Outstanding (#)(a)
Sandra N. Bane	3,410	14,621	18,031
Thomas D. Bell, Jr.	30,465	0	30,465
Norman R. Bobins	10,494	0	10,494
Charles R. Crisp	14,668	14,056	28,724
Brenda J. Gaines	10,082	0	10,082
Arthur E. Johnson	4,338	48,161	52,499
Wyck A. Knox, Jr.	12,122	46,400	58,522
Dennis M. Love	36,600	40,630	77,230
Charles H. McTier	2,428	15,311	17,739
Dean R. O'Hare	20,501	897	21,398
Armando J. Olivera	1,875	11,889	13,764
John E. Rau	20,840	0	20,840
James A. Rubright	19,469	25,272	44,741
Bettina M. Whyte	14,506	17,991	32,497
Henry C. Wolf	30,863	12,823	43,686

(a) Includes dividend equivalents.

Share Ownership and Holding Period Requirements for Non-Employee Directors

In order to serve on our board, directors are required to own shares of our common stock. Our share ownership guidelines for non-employee directors require that non-employee directors own shares of our common stock having a value of at least $475,000, which represents five times the value of the Equity Portion of the annual retainer. Each director has five years from the date of his or her initial election to meet the share ownership requirement. Common stock equivalents and shares issuable upon the exercise of vested stock options are included in the determination of the ownership guideline amount. We believe that the equity component of non-employee director compensation serves to further align the interests of the non-employee directors with the interests of our shareholders.

Under the terms of the Amended and Restated 2006 Non-Employee Directors Equity Compensation Plan (the "2006 Directors Plan"), non-employee directors are required to hold shares awarded under such plan until the earlier of (i) five years from the date of the initial stock award or subsequent stock grant; (ii) termination of the non-employee director's service; or (iii) a change in control of the Company. Shares subject to the holding period include all shares issued in connection with the initial stock award under the plan and all shares issued under the plan in payment of all or part of a director's annual retainer.

PROPOSAL 1—ELECTION OF DIRECTORS

GENERAL

The board of directors presently consists of 15 members, 14 of whom are non-employee directors. At the 2015 annual meeting, all 15 of the current directors will stand for re-election.

Vote Requirements for Election

Our bylaws provide that, in uncontested elections, a director must receive at least the majority of votes cast by shareholders with respect to his or her election at a meeting at which a quorum is present in order to be elected. Thus, each director nominee for whom the votes cast "FOR" election exceed 50% of the number of votes cast with respect to that director's election will be re-elected as a director. If any director nominee in an uncontested election does not receive the affirmative vote of a majority of the votes cast (including votes to withhold authority) with respect to that director's election, that director must promptly tender his or her resignation to the board following certification of the shareholder vote. The requirement that a director tender his or her resignation if he or she does not receive a majority of the votes cast does not apply in the case of a contested election where the number of nominees exceeds the number of directors to be elected.

Following such a tender of resignation, the Nominating, Governance and Corporate Responsibility Committee, excluding any director tendering his or her resignation if he or she is a member of the Nominating, Governance and Corporate Responsibility Committee, will make a recommendation to the board as to whether to accept or reject the resignation or whether other action should be taken. The board will then act on the Nominating, Governance and Corporate Responsibility Committee's recommendation and publicly disclose its decision and rationale within 90 days after the date of the certification of the election results. The director who tenders his or her resignation will not participate in the board's decision. If the director's resignation is not accepted by the board, the director shall continue to serve until his or her successor is duly elected or until his or her earlier death, resignation or removal. If the director's resignation is accepted by the board of directors, any resulting vacancy may be filled as provided in the bylaws or the board of directors may decrease the size of the board.

If a majority of the Nominating, Governance and Corporate Responsibility Committee does not receive a majority of the votes cast in their respective elections, then the independent members of the board who did not fail to receive a majority of the votes cast will appoint a committee from among themselves to consider the resignation offers and recommend to the board whether to accept them. If the only directors who did not fail to receive a majority of the votes cast constitute three or fewer directors, all directors may participate in the action regarding whether to accept the resignation offers.

Board Member and Nominee Qualifications

The experience, qualifications, attributes and skills that our board of directors considered in concluding that each of the current members of the board of directors and each of the nominees for election at the 2015 annual meeting should serve as a director include: (1) geographic representation (representative of our service territories); (2) diversity of professional skills and experience; (3) diversity of age, gender and race; (4) energy industry experience; and (5) community relations within our service territories.

When an incumbent director is up for re-election, the Nominating, Governance and Corporate Responsibility Committee reviews the performance, skills and characteristics of such incumbent director before making a determination to recommend that the full board nominate him or her for re-election.

A description of the specific experience, qualifications, attributes and skills that led our board of directors to conclude that each of the continuing members of the board of directors and each of the nominees should serve as a director follows the biographical information of each director and nominee below.

The board of directors, based on the recommendation of its Nominating, Governance and Corporate Responsibility Committee, has nominated Sandra N. Bane, Thomas D. Bell, Jr., Norman R. Bobins, Charles R. Crisp, Brenda J. Gaines, Arthur E. Johnson, Wyck A. Knox, Jr., Dennis M. Love, Dean R. O'Hare, Armando J. Olivera, John E. Rau, James A. Rubright, John W. Somerhalder II, Bettina M. Whyte and Henry C. Wolf for election as directors at the annual meeting. All of the nominees are current directors of the Company. If elected, each of the nominees will hold office for a one-year term expiring at the annual meeting of shareholders in 2016. Each of the nominees has agreed to serve as a director if elected by the shareholders.

If any nominee becomes unable to stand for election, the board may:

- designate a substitute nominee, in which case the proxies and the trustee of the AGL 401(k) Plan, as applicable, will vote all valid proxies for the election of the substitute nominee named by the board;
- allow the vacancy to remain open until a suitable candidate is identified; or
- reduce the authorized number of directors accordingly.

Nominees For Election

Sandra N. Bane, former audit partner with KPMG LLP from 1985 until her retirement in 1998; head of the Western Region's Merchandising practice at KPMG LLP and partner in charge of the region's Human Resources department for two years; accountant with increasing responsibilities at KPMG LLP from 1975 until 1996; currently a director of Big 5 Sporting Goods Corporation and Transamerica Asset Management Group, a mutual fund company; and formerly a director of PETCO Animal Supplies, Inc. Ms. Bane, 62, has been a director of AGL Resources since February 2008.

Ms. Bane brings many years of experience as an audit partner at KPMG with extensive financial accounting knowledge that is critical to our board of directors. Ms. Bane's experience with accounting principles, financial reporting rules and regulations, evaluating financial results and generally overseeing the financial reporting process of large public companies from an independent auditor's perspective and as a board member and audit committee member of other public companies makes her an invaluable asset to our board of directors.

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Thomas D. Bell, Jr., Chairman of Mesa Capital Partners, LLC, a real estate investment firm, since 2011; former Chairman of SecurAmerica LLC, a provider of premium contract security services, from January 2010 to September 2012; former Chairman and Chief Executive Officer of Cousins Properties Incorporated, a fully integrated real estate investment trust, from December 2006 until July 2009; President and Chief Executive Officer of Cousins Properties Incorporated from January 2002 until December 2006; real estate consultant to Credit Suisse First Boston from August 2001 until January 2002; special limited partner at Forstmann Little from January 2001 until July 2001; Chairman and Chief Executive Officer of Young & Rubicam, Inc. from January 2000 until November 2000; President and Chief Operating Officer of Young & Rubicam, Inc. from September 1999 until January 2000; Chairman and Chief Executive Officer of Young & Rubicam Advertising from March 1998 until August 1999; currently a director of Regal Entertainment Group, Norfolk Southern Corporation and the US Chamber of Commerce; and formerly a director of Cousins Properties Incorporated, Credit Suisse First Boston, Credit Suisse Group and Lincoln Financial Group. Mr. Bell, 65, has been a director of AGL Resources since July 2004. Mr. Bell previously served as a director of AGL Resources from July 2003 until April 2004.

Mr. Bell's extensive experience as a chief executive officer and chief operating officer of public companies demonstrates his leadership capability and business acumen. His experience with complex financial and operational issues in the real estate industry along with his service on the board of directors of a variety of public companies, including such companies' audit and compensation committees, brings valuable financial, operational and strategic expertise to our board of directors.

Norman R. Bobins, Chief Executive of Norman Bobins Consulting LLC, an independent consulting firm, since 2008; Chairman of The PrivateBank—Chicago since 2008; President and Chief Executive Officer of ABN AMRO North America from 2006 to 2007; Senior Executive Vice President of ABN AMRO Bank N.V. from 2002 to 2007; President and Chief Executive Officer of LaSalle Bank Corporation from 2003 to 2007; Chairman, President and Chief Executive Officer of LaSalle Bank from 2000 to 2007; President of LaSalle Bank Midwest from 2005 to 2007; currently a director of AAR Corp., Aviv Reit, Inc. and PrivateBancorp, Inc.; and formerly a director of SIMS Metal Management. Mr. Bobins, age 72, has been a director of AGL Resources since December 2011 and was a director of Nicor Inc. from 2007 to 2011.

Mr. Bobins has held several senior executive positions at various banking institutions, including LaSalle Bank Corporation, which was one of the largest bank holding companies in the Midwest, and where Mr. Bobins served as chairman, chief executive officer and president. Mr. Bobins' extensive knowledge of and experience in banking and finance and his prominent position in the Midwestern business community qualify him to serve on our board of directors. We also benefit from Mr. Bobins' extensive experience in leadership roles with numerous business, civic and philanthropic organizations in the Chicago area, which helps provide our Company with important business insights and access to other business leaders.

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Charles R. Crisp, former President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company, which provided energy-related products and services associated with wholesale natural gas and power, from 1999 until his retirement in October 2000; President and Chief Operating Officer of Coral Energy, LLC from 1998 until 1999; joined Houston Industries in 1996 and served as President of its domestic power generation group until 1998; served as President, Chief Operating Officer and a director of Tejas Gas Corporation from 1988 until 1996; joined Houston Pipe Line Co. in 1985 where he served as a Vice President, Executive Vice President and President until 1988; served as Executive Vice President of Perry Gas Companies Inc. from 1982 until 1985; began his career in the energy industry in 1969 with Conoco Inc. where he held various engineering, operations and management positions from 1969 until 1982; and currently a director of EOG Resources Inc., IntercontinentalExchange, Inc. ("ICE") and Targa Resources Corp. Mr. Crisp, 67, has been a director of AGL Resources since April 2003.

Mr. Crisp's extensive energy experience is critical to our board of directors. Mr. Crisp's vast understanding of many aspects of our industry and his experience serving on the board of directors of three other public companies in the energy industry are invaluable. In addition, Mr. Crisp's leadership and business experience and deep knowledge of various sectors of the energy industry provide our board of directors with crucial insight.

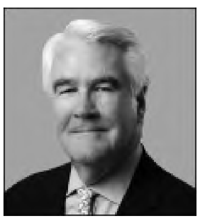
Brenda J. Gaines, former Chief Executive Officer of Diners Club North America, a division of Citigroup, a charge and credit card services company, from 2002 until her retirement in 2004; President of Diners Club North America from 1999 to 2004; Executive Vice President-Corporate Card Sales of Diners Club North America from 1994 to 1999; currently a director of Federal National Mortgage Association (Fannie Mae) and Tenet Healthcare Corporation; and formerly a director of CNA Financial Corporation and Office Depot, Inc. Ms. Gaines, 65, has been a director of AGL Resources since December 2011 and was a director of Nicor Inc. from 2006 to 2011.

Ms. Gaines has more than 25 years of experience working in the corporate and government arenas. She served as the deputy chief of staff and commissioner of housing for the City of Chicago. She has substantial training in corporate governance and has served as a speaker and panel member in various Risk Metrics certified courses on corporate governance, particularly those focusing on audit committees. As senior vice president, president and chief executive officer of Diners Club North America, Ms. Gaines led the activities for the North American franchise of the $29 billion Diners Club International network.

Ms. Gaines' business leadership skills, marketing knowledge, experience in government service and on the boards of directors of other companies qualify Ms. Gaines to serve on our board of directors. In addition, Ms. Gaines' corporate governance training and experience provides our board of directors with valuable insight and expertise.

Arthur E. Johnson, Lead Director of our board of directors since April 2009; former Senior Vice President, Corporate Strategic Development, of Lockheed Martin Corporation, an advanced technology company engaged in research, design, development, manufacture and integration of advanced technology systems, from 2001 until his retirement in March 2009; Vice President, Corporate Strategic Development, of Lockheed Martin Corporation from 1999 until 2001; President and Chief Operating Officer of Lockheed Martin Corporation Information and Services Sector from 1997 until 1999; President of Lockheed Martin Corporation Systems Integration Group from April 1996 until August 1997; President of Loral Corporation Federal Systems Group from 1994 until 1996; currently a director of Booz Allen Hamilton Inc., Eaton Corporation plc and an independent trustee of Fidelity Investments Fixed Income and Asset Allocation Funds; and formerly a director of Delta Air Lines Inc. and IKON Office Solutions Corporation. Mr. Johnson, 68, has been a director of AGL Resources since February 2002.

Mr. Johnson brings many years of experience in senior management with significant responsibilities in the areas of large company management and operations, business strategy development and strategic partnerships, which provide valuable insight to our board of directors. As we continue to evaluate growth opportunities, Mr. Johnson’s strategic planning insights have proven to be significantly beneficial to our board of directors. He also possesses extensive experience in the area of information services and technology that is extremely valuable to our board of directors. In addition, Mr. Johnson’s service on the board of directors of other public companies brings valuable experience and insight to our board of directors.



Wyck A. Knox, Jr., retired partner in, and former Chairman of the Executive Committee (for four years) of, the law firm of Kilpatrick Stockton LLP, now Kilpatrick Townsend & Stockton, LLP, or a predecessor firm, from 1976 until his retirement in 2007; and Chairman and Chief Executive Officer of Knox Rivers Construction Company from 1976 until 1995. Mr. Knox, 74, has been a director of AGL Resources since November 1998.

With over 47 years of legal experience and deep-rooted affiliations with a diverse array of business, political and philanthropic organizations in Georgia, Mr. Knox brings immense insight to the board of directors from the perspective of one of our largest service territories.

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Dennis M. Love, Chairman of the Board and Chief Executive Officer of Printpack Inc., which manufactures flexible and rigid packaging materials used primarily for consumer products, since 1987; currently a director of Oxford Industries, Inc.; and formerly a director of Caraustar Industries, Inc. Mr. Love, 59 has been a director of AGL Resources since October 1999.

Mr. Love's more than 25 years of experience as a chief executive officer brings key senior management and operational experience to our board of directors. Mr. Love's successful management and growth of his family-owned business to include international operations demonstrate his business strategy and acumen. His service on the nominating, compensation and governance committee of the board of directors of Oxford Industries also provides valuable insight on public company governance and compensation practices.

Dean R. O'Hare, former Chairman and Chief Executive Officer of The Chubb Corporation, a multi-billion dollar organization providing property and casualty insurance for personal and commercial customers worldwide, from 1988 until his retirement in November 2002; President of The Chubb Corporation from 1986 until 1988; Chief Financial Officer of The Chubb Corporation from 1980 until 1986; various other positions with increasing responsibility at The Chubb Corporation until being named officer from 1963 until 1972; currently a director of Fluor Corporation; and formerly a director of HJ Heinz Company. Mr. O'Hare, 72, has been a director of AGL Resources since August 2005.

As the former chief executive officer and chief financial officer of a Fortune 500 company with over 30 years of global business experience, Mr. O'Hare is a valuable member of our board of directors. Mr. O'Hare brings significant large public company operational, financial and corporate governance experience to our board of directors and his experience and relationships in one of our largest service territories, along with his service on the compensation committee and governance committee of the board of directors of Fluor Corporation, provide key insight to our board of directors. Mr. O'Hare's extensive experience with the Chubb Corporation also brings valuable risk management experience to our board of directors.

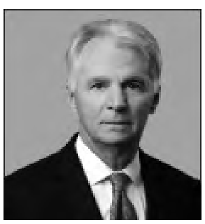
Armando J. Olivera, former President and Chief Executive Officer, Florida Power & Light Company ("FP&L"), an electric utility services company with over $10 billion in annual revenue, from June 2003 until his retirement in May 2012; various other positions with increasing responsibility at FP&L from 1972 to 2003; currently a director of Fluor Corporation, Consolidated Edison and Lennar Corporation; and formerly a director of FP&L. Mr. Olivera, 65, has been a director of AGL Resources Inc. since December 2011 and was a director of Nicor Inc. from 2008 to 2011.

Mr. Olivera was a 40-year veteran of FP&L. Throughout his career at FP&L, he served in several senior executive positions, including president and chief executive officer at the time of his retirement.

Mr. Olivera's experience in and understanding of utility regulation, operations and finance as well as his strong business leadership skills qualify him to serve on our board of directors. He has served in a leadership role on a number of electric utility industry groups including chairman of the Florida Reliability Council, chairman of the Association of Edison Illuminating Companies and president of the Southeastern Electric Exchange. He also has served in a number of community and educational organizations. He is currently a trustee of Miami Dade College and Cornell University and a director of Cornell Atkinson Sustainability Center.

John E. Rau, President and Chief Executive Officer of Miami Corporation, a private asset management firm, since December 2002; Chairman of Chicago Title and Trust Company Foundation, a charitable foundation, since March 2000; President and Chief Executive Officer of Chicago Title Corporation, a financial services corporation, from January 1997 to March 2000; currently a director of First Industrial Realty Trust, Inc. and BMO Financial Corp./BMO Harris Bank, N.A.; and previously a director of BorgWarner Inc. and Wm. Wrigley Jr. Company. Mr. Rau, 66, has been a director of AGL Resources since December 2011, was a director of Nicor Inc. from 1998 to 2011 and Nicor Inc.'s lead director from 2006 to 2011.

Mr. Rau is the chief executive officer of Miami Corporation, a private investment management company. He has served as chief executive officer at two major public companies and dean of Indiana University's Kelley School of Business. Mr. Rau also has served in leadership roles at numerous business, civic and philanthropic organizations. He has authored several dozen nationally published essays and reviews and a book on the characteristics of successful chief executive officers.
Mr. Rau's strong leadership skills, his service on other boards of directors and his extensive knowledge of banking, finance, economics and real estate qualify him to serve on our board of directors. Mr. Rau's prominent position in the Midwestern business community helps provide our Company with a wide variety of business insights and access to other business leaders.



James A. Rubright, former Chairman and Chief Executive Officer of RockTenn Company, an integrated paperboard and packaging company, from 1999 until his retirement in October 2013; and Executive Vice President of Sonat, Inc., an energy company, from 1994 until 1999; currently, Mr. Rubright is a principal in Privet Fund Management, LLC, a hedge fund management company, and is a director of Forestar Group, Inc. and HD Supply Holdings, Inc.; and formerly a director of Avondale, Inc., Oxford Industries, Inc. and RockTenn Company. Mr. Rubright, 68, has been a director of AGL Resources since August 2001.

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Mr. Rubright's experience on the board of directors of a variety of public companies along with his proven success as the chief executive officer of a large public company demonstrates his leadership capability and extensive knowledge of complex financial and operational issues that public companies face. In addition, his experience as a chief executive officer of a Fortune 500 company brings vital senior management experience and business acumen to our board of directors. Mr. Rubright's extensive experience in the natural gas industry provides valuable insight to our board of directors. Mr. Rubright's unique background brings a deep understanding of operations and strategy with an added layer of risk management experience that is an important aspect of the composition of our board of directors.

John W. Somerhalder II, our Chairman since October 2007 and our President and Chief Executive Officer since March 2006; Executive Vice President of El Paso Corporation, a natural gas and related energy products provider and owner of North America's largest natural gas pipeline system and one of North America's largest independent natural gas producers, from 2000 until May 2005, where he continued service under a professional services agreement from May 2005 until March 2006; President, El Paso Pipeline Group from 2001 until 2005; President of Tennessee Gas Pipeline Company, an El Paso company from 1996 until 1999; President of El Paso Energy Resources Company from April 1996 until December 1996; Senior Vice President, Operations and Engineering, El Paso Natural Gas Company from 1992 until 1996; Vice President, Engineering, El Paso Natural Gas Company from 1986 until 1990; from 1977 until 1990, various other positions with increasing responsibility at El Paso Corporation and its subsidiaries until being named an officer in 1990; and currently a director of AGL Resources Inc. and Crestwood Equity Partners LP. Mr. Somerhalder, 59, has been a director of AGL Resources since March 2006.

With over 30 years of energy industry experience at almost every level of a large public company, Mr. Somerhalder is well positioned to lead our management team and provide essential insight and guidance to the board of directors from an inside perspective of the day-to-day operations of the Company, along with experience and comprehensive knowledge of the natural gas industry.

Bettina M. Whyte, Managing Director and Senior Advisor, Alvarez & Marsal Holdings, LLC, a leading independent global professional services firm, since January 2011; Chairman of the Advisory Board of Bridge Associates, LLC, a leading turnaround, crisis and interim management firm, from October 2007 until December 2010; Managing Director and Head of the Special Situations Group of MBIA Insurance Corporation, a world leader in credit enhancement services and a global provider of fixed-income asset management services, from March 2006 until October 2007; Managing Director of AlixPartners, LLC, a business turnaround management and financial advisory firm, from April 1997 until March 2006; Partner and National Director of Business Turnaround Services, Price Waterhouse LLP from 1990 until 1997; and currently a director of Akal Security, Inc., Amerisure Companies and RockTenn Company. Ms. Whyte, 65, has been a director of AGL Resources since October 2004.

Ms. Whyte has vast experience in the financial and operational restructuring of complex businesses, and her service as interim chief executive officer, chief operating officer and chief restructuring officer of numerous troubled public and private companies is essential to our board of directors. Her experience on the board of directors of other public companies and her insight on financial and operational issues add value to our board of directors.

Henry C. Wolf, former Vice Chairman and Chief Financial Officer of Norfolk Southern Corporation, a holding company that controls a major freight railroad and owns a natural resources company and telecommunications company, from 1998 until his retirement in 2007; Executive Vice President—Finance of Norfolk Southern Corporation from 1993 until 1998; Vice President-Taxes of Norfolk Southern Corporation from 1991 until 1993; various other positions with increasing responsibility at Norfolk Southern Corporation in the finance division from 1973 until 1991; formerly a director of Hertz Global Holdings, Inc.; and currently serves as a trustee of Colonial Williamsburg Foundation. Mr. Wolf, 72, has been a director of AGL Resources since April 2004.

Mr. Wolf's unique professional background of over 40 years of experience with legal, financial, tax and accounting matters along with his demonstrated executive level management skills make him an important advisor. His skills are a vital asset to our board of directors at a time when accurate and transparent accounting, a sound financial footing and exemplary governance practices are essential. In addition, his background in strategic planning and experience with mergers and acquisitions in a regulated environment represent an important resource for the Company.

Under our Guidelines on Significant Corporate Governance Issues, each member of the board of directors is required to attend the annual meeting of shareholders unless unavoidable circumstances preclude attendance. All of our then current directors attended our 2014 annual meeting of shareholders.

THE BOARD OF DIRECTORS RECOMMENDS THAT SHAREHOLDERS VOTE "FOR" ALL OF THE ABOVE NOMINEES.

AUDIT COMMITTEE REPORT

The Audit Committee of the board of directors is composed of seven directors, each of whom is an independent director, as defined under the listing standards of the New York Stock Exchange and the Company's Standards for Determining Director Independence. The Audit Committee operates under a written charter adopted by the board of directors, a copy of which is available on the Company's website at *www.aglresources.com*.

The Audit Committee reviews the Company's financial reporting process on behalf of the board of directors. In fulfilling its responsibilities, the Audit Committee has reviewed and discussed the audited financial statements contained in the Company's Annual Report on Form 10-K for 2014 with management and the Company's independent registered public accounting firm, PricewaterhouseCoopers LLP. Management is responsible for the Company's financial statements and the financial reporting process, including the system of internal control over financial reporting. PricewaterhouseCoopers is responsible for expressing an opinion on the conformity of those audited financial statements with accounting principles generally accepted in the United States and on the effectiveness of the Company's internal control over financial reporting.

The Audit Committee has discussed with PricewaterhouseCoopers the matters required to be discussed by applicable audit standards adopted by the Public Company Accounting Oversight Board, including Auditing Standard No. 16, "Communication with Audit Committees," regarding PricewaterhouseCoopers' judgments about the quality of the Company's accounting principles as applied in its financial reporting. In addition, the Audit Committee has discussed with PricewaterhouseCoopers its independence from the Company and from Company management, including the matters in the written disclosures and the letter provided to the Audit Committee by PricewaterhouseCoopers as required by the applicable requirements of the Public Company Accounting Oversight Board. The Audit Committee has concluded that PricewaterhouseCoopers is independent from the Company and its management.

Based on the reviews and discussions referred to above, the Audit Committee recommended that the board of directors approve the inclusion of the audited financial statements in the Company's Annual Report on Form 10-K for 2014 for filing with the SEC.

Henry C. Wolf (Chair)
Sandra N. Bane
Norman R. Bobins
Brenda J. Gaines
Wyck A. Knox, Jr.
Dennis M. Love
Dean R. O'Hare

The information contained in the Audit Committee Report shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate it by reference in such filing.

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PROPOSAL 2—RATIFICATION OF THE APPOINTMENT OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2015

Appointment of Independent Registered Public Accounting Firm

PricewaterhouseCoopers LLP served as our independent registered public accounting firm and audited our annual financial statements for the fiscal year ended December 31, 2014, and the effectiveness of our internal control over financial reporting as of December 31, 2014.

PricewaterhouseCoopers has served as our principal independent registered public accounting firm since 2003.

The Audit Committee has appointed PricewaterhouseCoopers to be our independent registered public accounting firm for the fiscal year ending December 31, 2015. The shareholders are asked to ratify this appointment at the annual meeting. In the event shareholders do not ratify the appointment of PricewaterhouseCoopers as our independent registered public accounting firm for 2015, the Audit Committee will review its future selection of our independent registered public accounting firm.

Representatives of PricewaterhouseCoopers will attend the annual meeting and will have the opportunity to make a statement if they so desire. They will also be available to answer appropriate questions.

Audit and Non-Audit Fees

The following table summarizes certain fees billed by PricewaterhouseCoopers for 2014 and 2013:

Fee Category:	2014	2013
Audit fees	$ 4,247,068	$ 3,589,435
Audit-related fees	275,000	132,000
Tax fees	43,200	51,561
All other fees	0	27,000
Total fees	$ 4,565,268	$ 3,799,996

Set forth below is a description of the nature of the services that PricewaterhouseCoopers provided to us in exchange for such fees.

Audit Fees

Represents fees PricewaterhouseCoopers billed us for the audit of our annual financial statements, the review of our quarterly financial statements and services normally provided in connection with statutory and regulatory filings. These include fees incurred in meeting the internal control over financial reporting compliance requirements of Section 404 of the Sarbanes-Oxley Act of 2002, as well as fees for audits of several subsidiaries.

Audit-Related Fees

Represents fees PricewaterhouseCoopers billed us for audit and review-related services, including services relating to a review report on internal controls provided to third parties, potential acquisitions and dispositions and the audit of employee benefit plan financial statements.

Tax Fees

Represents fees PricewaterhouseCoopers billed us for tax compliance, planning and advisory services.

All Other Fees

Represents fees PricewaterhouseCoopers billed us for our attendance at accounting and tax conferences.

The Audit Committee pre-approved all of the above audit, audit-related, tax and other fees of PricewaterhouseCoopers, as required by the pre-approval policy described below.

Audit Committee Audit and Non-Audit Services Approval Policy

Consistent with rules and regulations pursuant to the Sarbanes-Oxley Act of 2002 regarding registered public accounting firm independence, the Audit Committee has responsibility for appointing, setting compensation and overseeing the work of the Company's independent registered public accounting firm. In recognition of this responsibility, the Audit Committee adopted a policy that requires specific Audit Committee approval before any services are provided by the independent registered public accounting firm.

Prior to engagement of the independent registered public accounting firm for the next year's audit, management submits to the Audit Committee for approval a summary of services expected to be rendered during that year and an estimate of the related fees for (1) audit services, (2) audit-related services, (3) tax services, and (4) all other services. The Audit Committee pre-approves these services by category of service and budget amount. The services and fees must be deemed compatible with the maintenance of the independent registered public accounting firm's independence. The Audit Committee requires the independent registered public accounting firm and management to report actual fees versus the budget periodically throughout the year by category of service. During the year, circumstances may arise when it may become necessary to engage the independent registered public accounting firm for additional services not contemplated in the original pre-approval. In those instances, the Audit Committee requires that management obtain specific approval from the Audit Committee before engaging the independent registered public accounting firm.

The Audit Committee may delegate approval authority to one or more of its members. The member to whom such authority is delegated must present for ratification any approval decisions to the Audit Committee at its next scheduled meeting.

THE BOARD OF DIRECTORS RECOMMENDS THAT SHAREHOLDERS VOTE "FOR" THE PROPOSAL TO RATIFY THE APPOINTMENT OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2015.

COMPENSATION COMMITTEE REPORT

The Compensation Committee of the board of directors is composed of eight directors, each of whom is an independent director, as defined under the listing standards of the New York Stock Exchange and the Company's Standards for Determining Director Independence. The Compensation Committee operates under a written charter adopted by the board of directors, a copy of which is available on the Company's website at *www.aglresources.com*.

The Compensation Committee has reviewed and discussed with management the "Compensation Discussion and Analysis," or CD&A, section of this proxy statement required by Item 402(b) of Regulation S-K promulgated by the SEC. Based on the Committee's review and discussions with management, the Committee recommended to the board of directors that the CD&A be included in the Company's 2014 annual report on Form 10-K and in this proxy statement.

Bettina M. Whyte (Chair)
Sandra N. Bane
Thomas D. Bell, Jr.
Norman R. Bobins
Charles R. Crisp
Armando J. Olivera
James A. Rubright
Henry C. Wolf

The information contained in the Compensation Committee Report shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate it by reference in such filing.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The following directors served on the Compensation Committee during 2014: Sandra N. Bane, Thomas D. Bell, Jr., Norman R. Bobins, Charles R. Crisp, Armando J. Olivera, James A. Rubright, Bettina M. Whyte (Chair) and Henry C. Wolf. None of such persons was, during 2014 or previously, an officer or employee of AGL Resources or any of its subsidiaries and each such person was an independent director as defined under the listing standards of the New York Stock Exchange and our Standards for Determining Director Independence. There were no Compensation Committee interlocks or insider participation in compensation decisions that are required to be disclosed in this proxy statement. None of the members of the Compensation Committee had any relationship requiring disclosure under "Certain Relationships and Related Transactions."

COMPENSATION DISCUSSION AND ANALYSIS

The following section contains a detailed description of our compensation objectives and policies, the elements of our compensation program, and the material factors the Compensation Committee considered in setting the compensation of our named executive officers for 2014, who are listed below:

Name	Title
John W. Somerhalder II	Chairman of the Board, President and Chief Executive Officer
Andrew W. Evans	Executive Vice President and Chief Financial Officer
Henry P. Linginfelter	Executive Vice President, Distribution Operations
Paul R. Shlanta	Executive Vice President, General Counsel, and Chief Ethics and Compliance Officer
Peter I. Tumminello	Executive Vice President, Wholesale Services, and President of Sequent Energy Management (Sequent)

Compensation Philosophy

Our compensation program is designed to reward employees for achieving our strategic and financial objectives; to attract, retain, motivate and reward top executive talent; and to foster long-term value creation for the Company and its shareholders. In support of this, our program is intended to:

- align executives' interests with those of our shareholders by creating a strong focus on stock ownership and basing pay on performance measures that are expected to drive long-term, sustained shareholder value growth;
- include a strong link between pay and performance, by placing a significant portion of compensation "at risk" based on Company and business unit performance;
- assure the Company's access to top executive talent and protect against competitor recruitment through compensation opportunities that are market competitive and commensurate with the executives' responsibilities, experience and demonstrated performance; and
- reinforce business strategies and reflect the Company's core values by rewarding desired performance, promoting desired competencies and recognizing contributions to business success that are consistent with those core values.

How We Tie Pay to Company Performance

Our executive compensation program contains three elements of total direct compensation: base salary, annual incentive, and long-term equity awards. Our program is structured so that a significant portion of target total direct compensation depends upon our achievement of certain goals and targets related to financial and operational performance, and our total shareholder return relative to our peer group. We believe these performance criteria strengthen the alignment between executive pay and value-creation for our shareholders.

Our annual incentive awards, which are paid in cash, are conditioned upon our achievement of pre-established performance goals. Annual incentive awards for Messrs. Somerhalder, Evans, Linginfelter and Shlanta are based upon achievement of an adjusted earnings per share goal, which we call "Plan EPS," and

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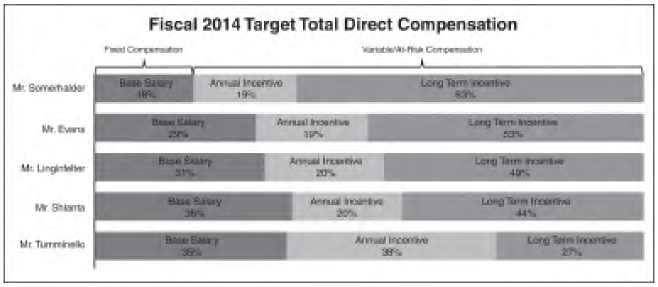
business unit goals, while Mr. Tumminello's annual incentive award is based primarily on pre-bonus accrual EBIT, which we call "Plan Earnings," of Sequent Energy Management, L.P. ("Sequent"), our wholesale services segment.

Our long-term equity awards consist of performance-based restricted stock units, which require achievement of an annual EBITDA target, and performance share units, which are earned based on our total shareholder return relative to our peer group over a period of three years.

As shown in the following chart, a significant portion of target total direct compensation for each of our named executive officers in 2014 was based on company or business unit performance requirements.



2014 Performance Highlights

- In 2014, we achieved the strongest financial results in our company's history; we generated net income from continuing operations attributable to AGL Resources of $562 million and diluted earnings per share (EPS) from continuing operations of $4.71, compared to net income from continuing operations attributable to AGL Resources of $290 million and diluted EPS from continuing operations of $2.45 in fiscal year 2013.
- We increased our annual dividend to shareholders by 4.1%, from $1.96 per share to $2.04 per share, continuing our strong track record of annual dividend increases.
- We generated total shareholder return (stock price appreciation and dividends) of 42% for the three-year period ended December 31, 2014.
- We completed the sale of our Tropical Shipping and Seven Seas Insurance businesses, generating approximately $225 million of after-tax proceeds and cash repatriation; the transaction enabled the company to exit a non-core business at a favorable multiple of EBITDA and will allow us to redeploy those proceeds in more strategic areas of regulated investment.
- We announced agreements to invest approximately $670 million in three interstate pipeline projects, which will ultimately enhance service to our utility customers in three of the states we serve (Georgia, New Jersey and Virginia), and which we expect to provide solid, FERC-regulated investment returns for our shareholders.
- We achieved important legislative and regulatory outcomes during 2014 in several of our state jurisdictions. These programs allow us to invest in our system infrastructure and continue to provide safe, reliable gas distribution service to our customers, while reducing the time required to recover our investments. As an example, our "Investing in Illinois"

program, approved in 2014, will enable us to invest $1.5 billion over the next nine years to enhance our Nicor Gas system and to grow our rate base substantially in Illinois.

2014 Performance and Compensation

Reflecting our pay-for-performance compensation philosophy, the compensation of our named executive officers was directly affected by our financial results in 2014, both with respect to the amount of annual incentive and long-term equity awards earned and the underlying value of long-term equity awards.

In the third quarter of 2014, we revised the way we account for the non-cash revenue that we recognize in connection with our infrastructure replacement programs. This impacted the timing of revenue recognition in our distribution operations segment. We also revised our method of amortizing our intangible assets in our retail operations segment and other uncorrected items. We corrected our accounting process for 2014, assessed the materiality of these items, and concluded that they were not material to any prior annual or quarterly periods and did not require an accounting restatement. However, we did revise our financial statements for the years ended December 31, 2013, 2012, and 2011, in an amended Form 10-K/A for the year ended December 31, 2013, and for the quarters ended March 31, 2014 and June 30, 2014, and the comparable periods in 2013, in amended Forms 10-Q/A for those periods. In addition, as previously reported, we determined that for 2011, had the underlying accounting originally reflected the distinction between regulatory accounting principles and GAAP, certain long-term incentives that were based upon results for the performance period ended December 31, 2011 would not have been awarded. The Compensation Committee of our board of directors and the full board took these items into consideration when determining 2014 executive compensation. For more information, see Note 1 to our audited Consolidated Financial Statements in our Annual Report on Form 10-K. For more information about the impact on our 2014 annual incentive program, see the discussion starting on page 48 of this proxy statement.

Annual Incentive Awards

- Our 2014 annual incentive awards were based upon a combination of several goals:
  - Corporate Plan EPS (described on page 49),
  - Margin, safety and customer service, and EBIT metrics for our regulated business segment (Distribution Operations) (described on page 51),
  - EBITDA metrics for our non-regulated business segments (described on page 51), and
  - Operating and Maintenance Expense minus Expenses Related to Benefits and Incentives (O&M Expense less B&I) for our regulated and non-regulated business segments (described on page 50).
- As noted above, 2014 was a successful year for the Company, and we met the Plan EPS hurdle and exceeded the target goals under the annual incentive plan. In calculating the “affordability factor” that applies to the 2014 annual incentive awards, the Compensation Committee decided to consider the full impact, both positive and negative, of the accounting revisions described above. Accordingly, the named executive officers earned an annual incentive plan payout for 2014 ranging from 169% to 177% of target. Please see the discussion of the annual incentive award program beginning on page 48.

- In light of the accounting revisions in 2014, including the impact on long-term incentives that were awarded for 2011 performance, the Compensation Committee decided to reduce the 2014 annual incentive payouts to certain individuals ultimately responsible for our accounting function, including our CEO and CFO. For more information about this adjustment of the 2014 annual incentive payout, see the discussion starting on page 53 of this proxy statement.
- We provide a separate annual incentive program for Mr. Tumminello, who serves as president of Sequent and leads our wholesale services segment and our storage and liquefied natural gas/fuels (storage and fuels) operations in our midstream operations segment. Mr. Tumminello's annual incentive is primarily based upon Sequent's Plan Earnings, with a smaller component based on the performance of midstream operations (storage and fuels). Based upon 2014 performance, Mr. Tumminello received an incentive plan award of $3,550,000, of which $1,593,020 was deferred for payout over a twenty-four month period in accordance with a mandatory retention provision in his program. Please see page 53 for a description of Mr. Tumminello's incentive program.

Long-Term Incentive Awards

- In 2014, we continued to grant performance-based restricted stock units (representing 30% of each executive's target long-term incentive value) and performance share units (representing 70% of each executive's target long-term incentive value). The restricted stock units include a one-year EBITDA hurdle and a four-year ratable time-based vesting schedule. Because the Company met the EBITDA hurdle, 25% of the RSUs granted in 2014 were vested and the remainder of the awards converted to time-vesting restricted stock for the remaining three years of the vesting period.
- The performance share units are earned based upon the Company's relative total shareholder return (RTSR) over a three-year period, compared to a peer group consisting of 12 comparable companies. The performance period for the performance share units granted in 2014 will be completed at the end of 2016.
- The performance share units granted in 2012, which had a three-year performance period that ended December 31, 2014, were earned at 83% of target because AGL's RTSR was at the 41.6 percentile ranking relative to its peer group. Please see the discussion of the long-term incentive awards beginning on page 55.

Continuity Agreements

- Each of our executives has a "continuity agreement" that provides severance pay if the executive's employment is terminated in certain circumstances in connection with a change in control of the Company. The agreements have a "double-trigger" provision, which means that severance benefits are not provided unless both (i) a change in control occurs and (ii) the executive incurs an involuntary termination within a designated period of time. The term of each continuity agreement runs through December 31, 2015. A description of the continuity agreements begins on page 57.

Limited Perquisites

- As in prior years, the only perquisite that we offer our executives is reimbursement for mandatory tax return preparation. To the extent that the entire authorized amount is not used for tax preparation, it may be applied to financial or estate planning.

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Changes in Compensation Program for 2014. As part of its ongoing effort to enhance and refine the compensation program, the Compensation Committee made several important changes to the compensation program for 2014:

- Effective January 1, 2014, base salaries were increased by 3% for Messrs. Somerhalder, Shlanta and Tumminello, and by 6% for Messrs. Evans and Linginfelter.
- Mr. Somerhalder's target long-term incentive opportunity for 2014 was equal to \$3.5 million (up from \$3.3 million in 2013), and Mr. Evans' target long-term incentive opportunity for 2014 was equal to 184% of his base salary (up from 160% of base salary in 2013). These changes were intended to provide each of these executive officers with a more fully competitive total direct compensation opportunity.
- Restricted stock units granted in 2014 vest ratably over four years (25% per year) including the performance year, provided that an EBITDA performance hurdle for the first year is met and the grantee remains in service through each such vesting date. In the past, our restricted stock units vested ratably over the three years following the performance year (33.3% per year in years 2, 3 and 4).
- Restricted stock units granted in 2014 also include dividend equivalent rights, so that dividends declared on Company common stock while an award remains outstanding will be credited to the award in the form of additional shares having a value equal to the dividend amount and being subject to the same vesting requirements. In the past, dividend equivalents were not credited to restricted stock unit awards. As in prior years, performance share units are not credited with dividend equivalents.

Governance and Evolving Compensation Practices

The Compensation Committee and Company management are mindful of evolving practices in executive compensation and corporate governance. In response, we have adopted certain policies and practices that are in keeping with "best practices" in many areas. For example:

- We do not provide excessive executive perquisites or extraordinary relocation benefits to our named executive officers.
- We do not provide tax gross-ups on compensation paid to our named executive officers, or on "golden parachute" excise taxes.
- Our Omnibus Performance Incentive Plan has "double-trigger" vesting for equity awards in the context of a change in control if the awards are assumed by the acquiring company.
- Our Omnibus Performance Incentive Plan expressly prohibits repricing of options (directly or indirectly) without prior shareholder approval.
- The Compensation Committee engages an independent compensation consultant.
- Our stock ownership policy requires that each executive must retain at least 75% of net shares from his or her equity awards until the ownership requirement is met.
- Company policy prohibits directors and executive officers from engaging in hedging activities involving Company stock.
- Company policy requires the recovery of certain incentive-based compensation paid to current or former executive officers in the event of an accounting restatement.

Say on Pay Results and Consideration of Shareholder Support

At the annual meeting of shareholders on April 29, 2014, over 95% of the votes cast were in favor of the advisory vote to approve executive compensation. The Compensation Committee considered this positive result and concluded that the shareholders continue to support the compensation paid to our executive officers and the Company's overall pay practices.

In light of this support, the Compensation Committee decided to retain the core design of our executive compensation program for 2014, with an emphasis on short and long-term incentive compensation that rewards our senior executives when they successfully implement our business plan and, in turn, deliver value for our shareholders.

The Committee will continue to monitor best practices, future advisory votes on executive compensation and other shareholder feedback to guide it in evaluating the alignment of the Company's executive compensation program with the interests of the Company and its shareholders. The Committee invites our shareholders to communicate any concerns or opinions on executive pay directly to the Board. Please refer to "Corporate Governance—Communications with Directors" on page 17 for information about communicating with the Board.

Based upon the preference expressed by our shareholders at the 2011 annual meeting, the Board has implemented an annual advisory vote on executive compensation. The next required vote on the frequency of shareholder votes on executive compensation is scheduled to occur at the 2017 annual meeting.

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How We Make Compensation Decisions

The Compensation Committee oversees our executive compensation program. Information about the Compensation Committee and its composition and responsibilities can be found on page 13 of this proxy statement, under the caption “Corporate Governance—Committees of the Board—Compensation Committee.” The Compensation Committee engages the services of Frederic W. Cook & Co., Inc. (F.W. Cook), an independent consultant. F.W. Cook reports directly to the Compensation Committee and provides no other services to the Company. The following table outlines the roles and responsibilities of various parties in determining executive compensation.

	Roles and Responsibilities
Compensation Committee	• Approves incentive programs and sets performance goals. • Determines appropriate levels of compensation for our executives, other than our CEO. • Recommends to independent Board members compensation opportunities and awards for our CEO.
F.W. Cook (Independent consultant to the Compensation Committee)	• Provides a competitive assessment of our executives’ compensation levels and programs. • Provides advice, research and analytical services on a variety of subjects, including compensation trends, best practices, peer group comparisons and the compensation of our non-employee directors.
Independent Directors on Full Board	• Evaluates CEO performance. • Approves compensation for our CEO.
CEO	• Develops an assessment of individual performance for each other named executive officer. • Provides recommendations to the Compensation Committee regarding individual compensation levels for such executives. • Provides recommendations to the Compensation Committee regarding goals for the performance measures in the incentive plans.
Other members of management	• Our Human Resources staff provides data and information relating to our compensation programs to the Compensation Committee and F.W. Cook to help facilitate the Compensation Committee’s review of competitive compensation practices. • Our chief financial officer provides the Compensation Committee with reports on financial performance as it relates to key business drivers and performance measures included in incentive program designs.

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Competitive Market Information

Each year the Compensation Committee works with F.W. Cook to review the market competitiveness of our executive compensation programs and levels and to re-evaluate the companies included in our comparator groups to ensure that we have the appropriate marketplace focus. For 2014, F.W. Cook prepared a competitive assessment of our executives' base salaries, target annual incentive awards, and long-term incentive opportunities, against an "energy industry database" and an "executive compensation peer group."

Energy Industry Database

For 2014, the "energy industry database" included energy services companies in Towers Watson's Energy Industry Services Compensation Database with assets or revenue between one-third and three times ours. This group was used as the primary source to assess competitive levels of compensation for our executives. We believe this larger selection of companies provides more accurate and reliable information than a smaller peer group and better reflects the labor market for our executive talent.

For 2014, the following forty companies were included in our energy industry database:

The AES Corporation
Alliant Energy Corporation
Ameren Corporation
Atmos Energy Corporation
Calpine Corporation
CenterPoint Energy, Inc.
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Resources Inc.
DTE Energy Company
Edison International
Energen Corporation
Entergy Corporation
EQT Corporation
First Solar, Inc.
IDACORP, Inc.
Integrys Energy Group, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.
NiSource Inc.
Northeast Utilities
NV Energy Inc.
OGE Energy Corp.
Pepco Holdings, Inc.
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
SCANA Corporation
Sempra Energy
Southwest Gas Corporation
Spectra Energy Corp.
TECO Energy, Inc.
UGI Corporation
UIL Holdings Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy Inc.

Executive Compensation Peer Group

In 2014, we also reviewed compensation data for 12 natural gas providers as a secondary point of reference. The companies in this "executive compensation peer group" were selected based upon their size and business operations. With assistance from F.W. Cook, the following criteria were developed for this group:

Size Requirements	***Industry Requirements***
Must be roughly one-third to three times our size in at least *two* of the following categories: • assets; • revenue; or • market capitalization	Must be a traditional natural gas local distribution company (LDC) and must meet at least *one* of the following: • includes non-regulated businesses such as storage, pipeline or construction services; • includes asset management/trading business similar to Sequent; or • conducts business in three or more states

To evaluate the peer group composition, F.W. Cook also considered:

- The comparator companies' disclosure of their own peer groups (particularly where they listed AGL Resources as a peer);
- Listings of comparator companies used in reports relating to the Company prepared by investment analysts and shareholder advisory services; and
- Mergers and acquisition activity for the comparator companies.

For 2014, the following twelve companies were included in our executive compensation peer group:

Atmos Energy Corporation
CenterPoint Energy, Inc.
Integrys Energy Group, Inc.
Laclede Group, Inc.[1]
New Jersey Resources Corporation
NiSource Inc.
Piedmont Natural Gas Company Inc.[1]
Sempra Energy
Southwest Gas Corporation
UGI Corporation
Vectren Corporation
WGL Holdings, Inc.

1 At the time the peer group was approved, Laclede and Piedmont met only one of the three size requirements (revenue for Laclede and market cap for Piedmont), but the Committee decided to include these companies due to the overall similarities in business characteristics with the Company.

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To perform a more meaningful analysis of Mr. Tumminello's compensation as the president of Sequent, F.W. Cook used the Towers Watson Energy Trading and Marketing Survey, which included data more directly comparable to Mr. Tumminello's position. This survey data included the following companies having energy trading and marketing operations:

Atmos Energy Corporation
BP
Cargill
CenterPoint Energy, Inc.
Chevron
Constellation Energy
Dominion Resources Inc.
EDF Trading
Iberdrola Renewables, Inc.
Nexen, Inc.
NRG Energy
Occidental Petroleum
ONEOK
PPL Corporation
Williams Energy Services

Compensation Elements and their Purpose

Our executive compensation program includes the following elements.

Compensation Element	***Overview/Objectives***
Base Salary	• Fixed portion of an executive's annual compensation; is intended to recognize fundamental market value for the skills and experience of the individual relative to the responsibilities of his or her position. • Foundation of our program; most other elements are determined as a percentage of base salary.
Annual incentive award[1]	• Annual cash incentive award is intended to vary as a direct reflection of Company and business unit performance. • Target opportunities are a percentage of base salary and represent the amount of money to be paid if expected performance is achieved. • Achievement of a performance hurdle is required for any payout. • Actual awards may range between 0% and 200% of target, based on performance against goals. • To achieve a 200% award, performance must meet or exceed the maximum performance levels for all performance measures.
Long-term incentive awards (performance-based restricted stock units and performance share units)	• Stock-based incentives reward performance over a multi-year period, link executive's interests to those of shareholders, and encourage retention. • Performance measures include EBITDA achievement for performance-based restricted stock units and total shareholder return, relative to the performance of the executive compensation peer group, for performance share units. • Vesting schedules serve to encourage retention and further tie an executive's compensation to stock price appreciation during the vesting period.

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Compensation Element	Overview/Objectives
Employee health and welfare and retirement benefit plans	• Competitive levels of medical, retirement and income protection, such as life and disability insurance coverage, are provided. • Executives participate in the same programs offered to all of our eligible employees. • To maintain consistent retirement benefit levels, we also provide non-qualified retirement benefits to executives and other highly-compensated employees who are adversely affected by limits imposed on contributions and total benefits under our retirement plans. The retirement plans available to the executives are described in more detail beginning on page 64.
Severance and other termination payments	• Severance benefits are provided in the event an executive's employment is terminated in certain circumstances in connection with a change in control of the Company. • Agreements provide security to executives so that they may focus on the Company and best interests of the shareholders during a transaction or potential transaction.
Financial planning / tax return preparation perquisite	• We reimburse executives for up to $18,000 per year for Company-mandated tax return preparation. We require professional tax return preparation as a means of ensuring tax compliance by our executives. To the extent that the entire amount is not used for tax preparation, it may be applied to financial or estate planning.

1 Mr. Tumminello's incentive program is described separately on page 53.

Setting 2014 Total Direct Compensation Opportunities

When setting base salary and target amounts for annual and long-term incentives, the Compensation Committee examined each component of pay on both a stand-alone basis and as a total. Pay decisions were based on the Compensation Committee's business judgment, informed by the comparative data, professional advice and other considerations, including the individual executive's experience and performance, internal pay equity and mastery of position responsibilities. As in prior years, target annual and long-term incentive values were set as a percentage of base salary for each of our named executive officers, other than Mr. Somerhalder's target long-term incentive, which was set as a specific amount, and Mr. Tumminello's target annual incentive, which was largely based on a percentage of Sequent's pre-bonus accrual EBIT.

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Fiscal 2014 Target Compensation Elements

	Base Salary	Target Annual Incentive ($ or % of Base Salary)	Target Long-Term Incentive ($ or % of Base Salary)	Target Total Direct Compensation
John W. Somerhalder II	$974,967	110%	$ 3,500,000	$ 5,547,431
Andrew W. Evans	$559,438	65%	184%	$ 1,952,440
Henry P. Linginfelter	$547,286	65%	160%	$ 1,778,680
Paul R. Shlanta	$449,143	55%	120%	$ 1,235,142
Peter I. Tumminello	$366,011	$ 391,250	75%	$ 1,031,768

Base Salaries

Each of the named executive officers received a 3% increase in base salary, effective January 1, 2014, except for Mr. Evans and Mr. Linginfelter, who each received a 6% increase. In determining base salary, the Compensation Committee considered competitive market base pay levels, as reflected in the competitive data provided by F.W. Cook, its general assessment of the performance of our CEO, and the performance assessments and recommendations for the other named executive officers presented to the Compensation Committee by our CEO. Performance assessments for base salary were subjective and non-formulaic and were not based upon any specific financial criteria.

Annual Incentive Awards

Performance Hurdle

Our annual incentive program is a subplan of the Company's Omnibus Performance Incentive Plan, which was approved by shareholders in 2011. Each of the named executive officers participates in the annual incentive program, other than Mr. Tumminello who participates in a separate program. Mr. Tumminello's incentive program is described separately on page 53.

For 2014, we continued the practice of utilizing a performance hurdle for our annual incentive program so that awards may qualify as performance-based compensation under Code Section 162(m). Achievement of the performance hurdle allows the Compensation Committee to fund the program up to the maximum payout level established for each award, or to provide for a lesser amount based upon the annual performance goals established by the Compensation Committee, which are described below. Achievement of the performance hurdle is required for any funding of the annual incentive program for the executive officers (for either the corporate component or the business unit component). The performance hurdle approved by the Compensation Committee for 2014 was Plan EPS of $2.64. The method of determining Plan EPS is described below under the heading "Corporate Measure."

Weighting of Executive Performance Goals

The performance measures for the 2014 annual incentive awards were derived from our annual operating plan and business strategy. The Compensation Committee approved a uniform weighting of goals for the named executive officers (other than Mr. Tumminello) as follows:

- 60% corporate performance, measured by Plan EPS
- 40% business unit performance, measured as described below

1. Corporate Measure

The annual incentive plan uses a corporate performance measure, which we refer to as “Plan EPS.” While EPS is a commonly understood metric, the Compensation Committee views EPS determined in accordance with generally accepted accounting principles (GAAP) as not accurately reflecting the value the Company created during a particular year with respect to our wholesale services segment (Sequent). For compensation purposes, we seek to consider and measure the economic value for the period in which it is generated, regardless of the period in which it is reported under GAAP. The method of determining 2014 Plan EPS was approved by the Compensation Committee at the time the performance goals were established.

In accordance with this method, when calculating 2014 Plan EPS, we started with GAAP EPS and subtracted the value created and credited for compensation purposes in 2013 which was expected to be reported in future periods, including 2014. We then added the value created and credited for compensation purposes in 2014 that will be reported on a GAAP basis in future periods. This was accomplished by adjusting for the economic value associated with Sequent’s storage and transportation positions.

At the time performance goals were established, the Compensation Committee also provided that 2014 Plan EPS would exclude the following:

- the effect of non-cash losses, including asset or goodwill impairment charges and loss on the sale of assets or subsidiaries;
- transaction costs associated with business combinations and related integration costs;
- changes in estimates or adjustments to actual settlement amounts equal to $100,000 or more related to legal issues existing at and prior to the closing date of an acquisition; and
- adjustments resulting from changes in GAAP.

For 2014, the Compensation Committee approved a Plan EPS “target” amount of $2.84, which would result in a 100% payout of the corporate component. This target amount:

- was consistent with the midpoint of our initial published range of earnings guidance (excluding wholesale services) of $2.75 for 2014, plus $0.70 of expected EPS on a GAAP basis to be generated by the wholesale services segment as included in our 2014 earnings guidance;
- was expected to be an appropriate target when considering our 2014 business objectives; and
- took into consideration the anticipated volatility and treatment of earnings from our wholesale services business unit.

The Compensation Committee also approved a “threshold” Plan EPS of $2.74, which must be met before any corporate performance component could be earned. At “threshold” performance, the corporate component would pay out at 50%.

Below threshold performance, no corporate component would be paid, but as long as the $2.64 Plan EPS performance hurdle was met, the business unit components would be eligible to pay out based on actual business unit outcomes.

As shown in the table below, actual Plan EPS for 2014 was $3.99, which is above both the performance hurdle and the threshold goal set for 2014. Accordingly, the named executive officers earned a payout related to the corporate performance component.

2014 Corporate Measure—Goals and Results

	Performance Hurdle 162(m) Qualifier	Threshold (50%)	Target (100%)	150%	Maximum (200%)	Actual Plan EPS
GAAP EPS(1)	$ 3.06	$ 3.16	$ 3.26	$ 3.36	$ 3.46	$ 4.71
Adjusted for value created by wholesale services in 2013 which was reported on a GAAP basis in 2014(2)	(0.52)	(0.52)	(0.52)	(0.52)	(0.52)	(0.52)
Adjusted for ***expected*** value to be created by wholesale services in 2014 which will be recognized on a GAAP basis in future periods	0.10	0.10	0.10	0.10	0.10	—
Adjusted for ***actual*** value created by wholesale services in 2014 which will be recognized on a GAAP basis in future periods	—	—	—	—	—	(0.20)
Plan EPS	$ 2.64	$ 2.74	$ 2.84	$ 2.94	$ 3.04	$ 3.99

(1) Diluted EPS from continuing operations attributable to AGL Resources Inc.
(2) Used in the calculation of 2013 Plan EPS.

2. Business Unit Measures

The business unit component of the annual incentive plan uses performance measures and key operating metrics for the following regulated and non-regulated business segments:

Regulated	Non-Regulated
Distribution Operations	Wholesale Services
	Retail Operations
	Midstream Operations

These performance measures and metrics, which are described in more detail below, accounted for 80% of the AIP business unit component for each of the named executive officers in 2014.

In addition, we also use another measure that we refer to as “O&M Expense Less B&I,” which relates to a business unit’s operating and maintenance expense, including inflationary costs, minus expenses related to benefits and incentives, such as pension, postretirement, healthcare and other employee benefits as well as expenses related to annual and long-term incentive compensation. O&M Expense Less B&I reflects our ability to manage our cost structure, which is critical to meeting the corporate AIP targets described above. O&M Expense Less B&I accounted for 20% of the AIP business unit component for each of the named executive officers in 2014.

For 2014, the Compensation Committee approved the same weighting of the three business unit categories (regulated, non-regulated, and O&M Expense Less B&I) for each of the participating named executive officers, other than for Mr. Linginfelter, our Executive Vice President, Distribution Operations, whose business unit goals remain focused on the regulated business.

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2014 Business Unit Measure—Goals and Weightings

Name	Regulated Business (Distribution Operations)[1]	Non-Regulated Businesses[2]	O&M Expense Less B&I	Total
John W. Somerhalder II	50%	30%	20%	100%
Andrew W. Evans	50%	30%	20%	100%
Henry P. Linginfelter	80%	—	20%	100%
Paul R. Shlanta	50%	30%	20%	100%

(1) Performance for the regulated business was based on composite results.
(2) Performance for the non-regulated businesses was weighted as follows:

Non-Regulated Business Unit Weightings	
Wholesale Services	45%
Retail Operations	45%
Midstream Operations	10%

Business unit measures for our regulated business (Distribution Operations) were based upon margin goals (20%) and specific metrics relating to safety and customer service (80%). In addition, these measures were multiplied by an "affordability factor" that would serve to reduce the payout level based upon the business unit's EBIT, with results interpolated on a straight line basis between the following performance levels:

Distribution Operations Performance (EBIT)—Affordability Factor

EBIT	< $575 million	$575 million	$585 million	$595 million
Affordability Factor (level of funding)	0%	50%	75%	100%

Because distribution operations was expected to contribute approximately 75% of the Company's EBIT for 2014, the affordability factor served to ensure a level of earnings contribution from distribution operations that we believed was appropriate to fund any of the business unit measures. Accordingly, the affordability factor was applied to both the regulated and non-regulated business units. The Company revised its financial statements for the first six months of 2014 to, among other matters, correctly exclude the deferred return on equity in connection with infrastructure replacement programs. The revised accounting resulted in a decrease in revenue related to regulatory assets and a related decrease in interest expense. The affordability factor, which is based on EBIT, reflects the impact of the decreased revenue but not the benefit of the decreased interest expense under our revised accounting. In the Compensation Committee's judgment, in considering the purpose of the affordability factor, it was determined that it was also appropriate to reflect the benefit of decreased interest expense. As adjusted, this resulted in an affordability factor of 90%. In the Compensation Committee's judgment, this adjustment was appropriate to accurately reflect the effect on the affordability factor of the full impact of the accounting revisions.

Business unit measures for our non-regulated businesses were based upon EBITDA for each business unit. The non-regulated business measures did not include a separate affordability factor because the performance measures already include EBITDA targets. However, as described above, the funding of the non-regulated business unit measures was dependent upon the EBIT performance of distribution operations and the corresponding affordability factor.

Business unit goals, derived from the budget approved by the board, were determined for each named executive officer, other than Mr. Tumminello, including a threshold, below which no award would be provided, a target amount, and a maximum award of 200%. These performance ranges were set in a qualitative, non-formulaic manner, based upon a combination of historical performance and our expected performance for 2014. The performance for each business unit goal was measured independently and combined based on the weightings described above to determine a final business unit performance score. The following table reflects the payout percentage at different performance levels.

	Business Unit Performance Score Achieved	Payout %[1]
Minimum	**50%**	**0%**
	60%	20%
	70%	40%
	80%	60%
	90%	80%
Target	**100%**	**100%**
	110%	120%
	120%	140%
	130%	160%
	140%	180%
Maximum	**150%**	**200%**

(1) As noted above, the final payout amount for the AIP business unit component for each named executive officer, other than Mr. Tumminello, was conditioned on the $2.64 Plan EPS performance hurdle being met and was subject to the affordability factor based on EBIT of distribution operations.

Review of Awards and Reductions for Certain Executives

The Compensation Committee reserves the right to adjust performance objectives during the course of the year in order to reflect changes in the Company and our business. In determining the corporate performance components under our Omnibus Performance Incentive Plan, the Compensation Committee has the authority to: (i) exclude extraordinary one-time effects, which could increase or decrease award payments, if, in its business judgment, our Company and our shareholders are better served by that result; and (ii) exercise negative discretion against reported results which would serve to reduce an award otherwise due.

As described above, the Compensation Committee determined that it was appropriate to factor in decreased interest expense in the calculation of the affordability factor for the 2014 annual incentive award.

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In addition, after considering the 2014 accounting revisions and other issues relating to our accounting processes and controls in 2014, as well as the long-term incentives that were awarded based upon results for the performance period ended December 31, 2011 that would not have been awarded under our revised accounting for that period, the Compensation Committee exercised its negative discretion to reduce the final annual incentive award payouts for 2014 for certain individuals ultimately responsible for our accounting function, including the following reductions for our CEO and CFO.

Discretionary Reduction to 2014 AIP Payouts	
John W. Somerhalder II	($500,000)
Andrew W. Evans	($175,000)

For 2014, the Compensation Committee did not exercise discretion in connection with the calculation of any other performance goals or amounts.

Annual Incentive Performance Composite Results

The following table provides the aggregate weighted result of all performance measures (corporate and business unit) for each of the named executive officers, other than Mr. Tumminello. This amount was multiplied by the executive's target opportunity (expressed as a percentage of salary) to determine the actual amount earned.

2014 Annual Incentive Award—Composite Performance and Results

	Corporate Payout Percentage (60% weighting)	Business Unit Payout Percentage (40% weighting)	Total Payout Percentage	2014 Target Opportunity (% of Base Salary)	Calculated Payout Amount	Discretionary Reduction by Compensation Committee	2014 Annual Incentive Payout
John W. Somerhalder II	200%	134%	174%	110%	$1,852,563	($500,000)	$1,352,563
Andrew W. Evans	200%	143%	177%	65%	$ 637,102	($175,000)	$ 462,102
Henry P. Linginfelter	200%	122%	169%	65%	$ 594,383	—	$ 594,383
Paul R. Shlanta	200%	143%	177%	55%	$ 435,470	—	$ 435,470

Annual Incentive Award for Mr. Tumminello

For 2014, Mr. Tumminello's annual incentive award primarily was based on Plan Earnings for wholesale services, as described below. This is consistent with our philosophy of placing greater emphasis upon the cash compensation of members of our wholesale services segment. As president of Sequent, Mr. Tumminello was eligible to receive an amount under our Omnibus Performance Incentive Plan equal to 9.375% of an incentive pool established for employees of Sequent under the Sequent Incentive Plan (Sequent Plan), calculated as if he were an actual participant in the Sequent Plan. The first 8.125% of the incentive pool under the Sequent Plan is regarded as "target" performance, and the remaining 1.25% may be earned based on Mr. Tumminello's individual performance as assessed by our chief executive officer and approved by the Compensation Committee.

The Sequent incentive pool was funded based on a pre-determined formula. The 2014 pool funded at a rate of 12% of Sequent's pre-bonus accrual EBIT ("Plan Earnings"). When calculating 2014 Plan Earnings for Sequent, we started with Sequent's pre-bonus accrual EBIT, adjusted for its interest expense for 2014 and the December 31, 2013 rollout value associated with storage and transportation hedges, added the December 31, 2014 rollout value associated with storage and transportation hedges, and adjusted for other items, as defined by the plan and consistent with historical practice. At the time performance goals were established, the Compensation Committee also provided that for purposes of calculating the pre-bonus accrual EBIT for Mr. Tumminello's annual incentive award, any one-time, non-recurring items under GAAP arising during 2014 would be excluded, and Sequent's 2014 Plan Earnings would exclude the same items excluded in the calculation of Plan EPS, as described on page 49.

Similar to prior years, the Compensation Committee authorized an additional incentive for Mr. Tumminello having a target payout amount of $50,000 (with up to $100,000 maximum payout amount), which he was eligible to earn based upon the 2014 EBITDA performance of midstream operations (storage and fuels), which he oversees. The storage and fuels component was conditioned upon the Company achieving the performance hurdle of $2.64 Plan EPS.

For 2014, Sequent's Plan Earnings were $324.7 million, which after adjustment resulted in the funding of an incentive pool of approximately $37.7 million. Mr. Tumminello's annual incentive payout amount was $3,550,000 and was calculated as follows:

2014 Annual Incentive Award for Mr. Tumminello—Composite Performance and Results

8.125% of Sequent Pool	$	3,064,616
Individual Performance	$	473,769
Midstream Operations Performance		
Storage and Fuels component	$	11,615
Total Incentive Award	$	3,550,000

The Sequent Plan provides that if Mr. Tumminello's annual incentive award exceeds his base salary, then 50% of the overage is subject to mandatory deferral. Under this mandatory deferral provision, one half of the deferred amount is paid twelve months after the initial incentive payment, and the other half is paid twenty-four months after the initial payment. This deferral feature is intended to act as a retention vehicle. Of Mr. Tumminello's 2014 incentive award, a total of $1,593,020 was deferred for payout over twenty-four months.

Though not subject to an absolute maximum, the size of the Sequent Plan incentive pool, and correspondingly Mr. Tumminello's annual incentive award, is constrained by a framework of established risk parameters including open position limits, value-at-risk limits, stop-loss limits, and credit limits.

The Compensation Committee has reviewed management's analysis of the Sequent Plan and determined that because of the operational limits on Sequent and the risk management oversight by the Company, the Sequent Plan does not incent excessive risk taking.

Long-term Incentive Awards

Two types of long-term incentive grants were awarded in 2014. Performance-based restricted stock units (representing 30% of each executive's target long-term incentive value), and performance share units (representing 70% of each executive's target long-term incentive value) were selected based on the following factors:

- the impact each type of award has on shareholder value creation and executive motivation and retention;
- competitive practice; and
- balancing the cost of equity awards and the projected impact on shareholder dilution.

Performance-based Restricted Stock Units

Restricted stock units have a one-year measurement period, and their vesting is contingent on the Company's achievement of a Corporate EBITDA goal during that period. The EBITDA threshold is set at a level to ensure adequate cash flow to fund dividends and capital expenditure commitments. If the threshold goal is met, one-fourth of the restricted stock units vest immediately, and the remaining three-fourths are subject to annual time-based vesting over the remaining three years of the vesting period. The restricted stock units convert to an equal number of shares of restricted stock during this time-vesting period, except for Mr. Somerhalder, whose awards remain restricted stock units during the entire vesting period. Dividends declared on Company common stock while an award remains outstanding will be credited to the award in the form of additional shares having a value equal to the dividend amount and being subject to the same vesting requirements. The restricted stock unit awards are designed to focus the executives on the Company's EBITDA and to provide retention value during the vesting period.

For 2014, because the Company's EBITDA exceeded the threshold for the restricted share units, one-fourth of the awards vested on March 1, 2015, and the remaining units were converted to restricted stock with annual time-based vesting through 2018, except for Mr. Somerhalder, whose award remains restricted stock units during such vesting period. The value of these awards as of the date of grant is reflected in the 2014 Grants of Plan-Based Awards Table and in the Stock Awards column of the Summary Compensation Table.

Performance Threshold (Corporate EBITDA)	Actual Result (Corporate EBITDA Achieved)
$1.0 billion	$1.5 billion

Performance Share Units

Performance share units (PSUs) vest over a three-year period with a performance measure based upon Relative Total Shareholder Return (RTSR). RTSR is measured by ranking the relative stock price and dividend performance of our Company to the companies in the executive compensation peer group described on page 45. The use of RTSR as a performance measure requires executive focus that is aligned with the interests of shareholders and provides diversity in our use of performance indicators.

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For the purposes of determining PSUs, Total Shareholder Return is defined as:

Price $_{begin}$ = share price at the beginning of the period
Price $_{end}$ = share price at the end of the period
Dividends = total dividends paid for the period
TSR = (Price $_{end}$ – Price $_{begin}$ + Dividends)/Price $_{begin}$

Once the actual performance is computed, PSUs earned may increase or decrease from target grant levels, depending upon our performance relative to our executive compensation peer group, according to the following scale:

TSR Rank	Percentile Rank	Shares Earned as % of Target Shares	
1	100%	200%	Maximum
2	92%	184%	
3	83%	166%	
4	75%	150%	
5	67%	134%	
6	58%	116%	
7	50%	100%	Target
8	42%	84%	
9	33%	66%	
10	25%	50%	Threshold
>10	0%	0%	

The resulting awards will be settled half in cash and half in shares. To promote officer share ownership, the cash portion must first be used to cover the taxes incurred from the total award.

Performance share units are not credited with dividend equivalents. When determining the number of PSUs to be granted, however, the Compensation Committee factors in the value of dividends expected to be paid during the vesting period.

During the most recently completed three-year performance period (January 1, 2012 to December 31, 2014), the Company achieved an RTSR percentile rank of 41.6%, which exceeded the threshold target level and resulted in 83% of the target PSUs earned. Accordingly, the PSUs granted in 2012 (having a 2012-2014 performance period) paid out in the following amounts:

Payout of 2012 PSUs (2012-2014 Performance Period)

Name	Shares (#)	Cash ($)
John W. Somerhalder II	23,178	1,263,201
Andrew W. Evans	5,761	313,920
Henry P. Linginfelter	5,632	306,944
Paul R. Shlanta	3,569	194,511
Peter I. Tumminello	1,818	99,081

Continuity Agreements

Each of our executives has a change-in-control severance agreement, referred to as a Continuity Agreement. The Compensation Committee believes these agreements are desirable because of the retentive value they would provide during critical periods relating to potential change in control. Each of the agreements in place in 2014 has a term that runs through December 31, 2015. These agreements do not contain an excise tax gross-up and provide that no severance payments or benefits may be paid under the agreements unless a change in control is actually consummated and the executive has a qualifying termination of employment.

Tables disclosing the estimated costs associated with these agreements, and footnotes describing their principal terms, begin on page 67 under the heading "Potential Payments upon Termination or Change in Control."

Other Policies Governing our Executive Compensation Program

Grants of Long-Term Incentive Awards

In January 2014, the Compensation Committee adopted a Policy on Granting Equity Compensation Awards. Pursuant to the policy, annual equity awards typically are granted on the third trading day following the Company's release of year-end financial results. Such awards are approved not more than 30 days in advance by the Compensation Committee or the board. The number of shares subject to each such equity award is determined based on the dollar value for the awards approved by the Committee or the board and the fair market value of the Company's common stock on the grant date. The policy prohibits the Compensation Committee, the board, and any member of the Company's management from backdating or manipulating any equity award, or manipulating the timing of the public release of material information or of any equity award with the intent of benefitting a recipient of the award.

Recoupment Policy

The Company maintains a compensation recoupment policy that became effective January 1, 2012. This policy provides that in the event that the Company is required to prepare an accounting restatement due to material noncompliance with financial reporting requirements under the U.S. securities laws, it will seek to recover from any current or former executive officer incentive-based compensation (including equity compensation) received during the three-year period preceding the date on which the accounting restatement was required to be made. The amount to be recovered is the excess of the amount paid calculated by reference to the erroneous data, over the amount that would have been paid to the executive officer calculated using the corrected accounting statement data. This compensation recovery would be applied regardless of whether the executive officer engaged in misconduct or otherwise caused or contributed to the requirement for the restatement.

As described above on page 39 of this proxy statement, in 2014 we revised our financial statements for certain prior periods. The Company assessed the materiality of the adjustments involved and concluded that they were not material to any prior annual or interim period and that the Company was not required to prepare an accounting restatement. Accordingly, the provisions of our compensation recoupment policy were not applicable to this revision.

Hedging and Pledging Policies

Company policy prohibits directors and executive officers from engaging in hedging activities involving Company stock. Holding Company stock in a margin account or pledging Company stock as collateral for a loan is discouraged by company policy and requires the prior approval of the Company's Chief Ethics and Compliance Officer.

Accounting and Tax Treatment of Direct Compensation

Under current accounting principles, we do not expect accounting treatment of differing forms of awards to vary significantly. Accordingly, although accounting treatment is a consideration, we do not expect it to have a material effect on our selection of forms of compensation.

Section 162(m) of the Code places a limit of $1,000,000 on the amount of compensation that we may deduct in any one year with respect to any one of our named executive officers, other than the CFO. However, qualifying performance-based compensation will not be subject to the deduction limit if certain requirements are met. The Omnibus Performance Incentive Plan is designed to allow the Compensation Committee to grant equity awards that may qualify for the performance-based compensation exemption from Section 162(m), such as restricted stock units and performance cash awards. The annual incentive program, as a subplan of the Omnibus Performance Incentive Plan, also allows annual cash incentive awards that may qualify as performance-based compensation.

The Compensation Committee generally expects that awards under our long-term incentive programs and the annual incentive for executives will qualify as performance-based compensation under Section 162(m), but such tax treatment is not guaranteed. In addition, to maintain flexibility in compensating our executives, the Compensation Committee reserves the right to use its judgment to adjust performance goals or to authorize compensation payments that may cause the awards to be subject to the Section 162(m) limit when the Compensation Committee believes that such adjustments or payments are appropriate.

Stock Ownership

We maintain stock ownership guidelines designed to ensure sustained, meaningful executive share ownership, align executive long-term interests with shareholders, and demonstrate the commitment of our officers to enhancing long-term shareholder value. Each of our executive officers is encouraged to own shares of our common stock having a market value equal to or exceeding a given multiple of his or her annual base salary–five times for Mr. Somerhalder, and three times for each of the other named executive officers. The guidelines require that each executive retain at least 75% of net shares (after tax withholding) from their equity awards until the ownership requirements are met. In calculating compliance with the ownership guidelines, we include all of the stock owned by an executive, restricted stock and in-the-money value of vested stock options, and stock included in an executive's account under our Retirement Savings Plus Plan and Nonqualified Savings Plan. As of December 31, 2014, each of our named executive officers met the ownership guidelines.

2015 Compensation Program

The Compensation Committee and the board of directors approved several changes to the compensation program for 2015:

- Effective January 1, 2015, base salaries for the executive officers were increased by 3%, which is consistent with our overall increase budget for salaried employees.
- Performance share units granted in 2015 will have two performance metrics – relative total shareholder return (weighted at 75%) and cumulative earnings per share (weighted at 25%) – which will be measured over a three-year performance period.

EXECUTIVE COMPENSATION

Compensation Paid to Named Executive Officers

The Summary Compensation Table below reflects the total compensation earned by our chief executive officer, our chief financial officer and each of our three most highly compensated executive officers who served as an executive officer as of December 31, 2014. These five officers are our "named executive officers."

Summary Compensation Table

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(3)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5)	All Other Compensation ($)(6)	Total ($)
John W. Somerhalder II	2014	969,506	—	4,372,269	—	1,352,563	970,956	159,041	7,824,335
Chairman, President and	2013	931,725	—	3,671,374	—	1,921,067	0	64,050	6,588,216
Chief Executive Officer	2012	919,000	—	3,223,441	—	0	321,622	63,388	4,527,451
Andrew W. Evans	2014	553,349	—	1,286,041	—	462,102	351,600	75,687	2,728,779
Executive Vice President	2013	517,524	—	912,260		632,932	0	40,482	2,103,198
and Chief Financial Officer	2012	512,400	—	1,401,144	—	0	140,525	42,245	2,096,314
Henry P. Linginfelter	2014	541,329	—	1,094,114	—	594,383	449,150	71,654	2,750,630
Executive Vice President,	2013	508,211	—	892,180	—	617,334	0	39,356	2,057,081
Distribution Operations	2012	501,270	—	1,383,371	—	0	186,959	29,584	2,101,184
Paul R. Shlanta	2014	446,627	—	673,292	—	435,470	363,058	64,234	1,982,681
Executive Vice President, General Counsel and	2013	424,917	—	565,129	—	442,494	0	39,475	1,472,015
Chief Ethics and	2012	423,360	—	496,094	—	0	154,754	37,615	1,111,823
Compliance Officer									
Peter I. Tumminello	2014	363,961	—	343,157	—	3,550,000	297,880	58,092	4,613,090
Executive Vice President, Wholesale Services	2013	349,777	200,000(2)	488,412	—	798,076	0	45,560	1,881,825
and President, Sequent Energy Management,	2012	345,000	—	852,931	—	245,453	111,298	29,403	1,584,085
LP									

(1) For each of the named executive officers, includes salary that was eligible for deferral, at the election of the named executive officer, under our Retirement Savings Plus Plan and Nonqualified Savings Plan.

(2) Reflects the cash portion of a special award granted to Mr. Tumminello in connection with the sale of Compass Energy Services in 2013.

(3) Reflects the aggregate grant date fair value of stock awards, which was computed in accordance with FASB ASC Topic 718 without regard to estimated forfeitures related to service-based vesting conditions. The assumptions used in calculating these amounts are incorporated by reference to Note 7—"Stock-Based Compensation" to the financial statements in our annual report on Form 10-K filed with the SEC on February 12, 2015. The grant date fair value of the restricted stock units granted in 2014 was determined by reference to the closing price of the shares on the grant date. The grant date fair value of the performance unit awards granted in 2014 was computed by multiplying (i) the target number of units awarded to each named executive officer, which was the assumed probable outcome as of the grant date, by (ii) the closing price of the underlying shares on the grant date. Assuming, instead, that the highest level of performance conditions would be achieved, the grant date fair values of these performance unit awards would have been $6,652,400 for Mr. Somerhalder, $1,956,909 for Mr. Evans, $1,664,735 for Mr. Linginfelter, $1,024,788 for Mr. Shlanta and $522,206 for Mr. Tumminello.

(4) Reflects annual incentive compensation earned under our annual incentive plan (or Mr. Tumminello's annual incentive arrangement).

(5) Reflects the aggregate change in the actuarial present value of the named executive officer's accumulated benefit under the Retirement Plan, which we refer to as the Pension Plan, and the Excess Plan, both of which are defined benefit plans, and, in addition, for Mr. Somerhalder, under the terms set forth in an individual agreement. None of the named executive officers received any interest on deferred compensation at an above-market rate of interest.

(6) The following table reflects the items that are included in the "All Other Compensation" column for 2014.

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All Other Compensation Detail

Name	Company Contributions to the Retirement Savings Plus Plan ($)(a)	Company Contributions to the Nonqualified Savings Plan ($)(a)	Perquisites ($)(b)	Other Income ($)	Total All Other Compensation ($)
John W. Somerhalder II	13,520	131,521	14,000	—	159,041
Andrew W. Evans	11,375	50,312	14,000	—	75,687
Henry P. Linginfelter	13,520	46,730	11,404	—	71,654
Paul R. Shlanta	13,520	32,714	18,000	—	64,234
Peter I. Tumminello	13,520	30,572	14,000	—	58,092

(a) Amounts of matching contributions contributed by the Company to the Retirement Savings Plus Plan and Nonqualified Savings Plan are calculated on the same basis for all plan participants in the relevant plan, including the named executive officers.

(b) Reflects the incurred cost to the Company in connection with financial planning and tax return preparation benefits.

Grants of Plan-Based Awards

The following table presents information concerning plan-based awards granted to each of the named executive officers during 2014.

2014 Grants of Plan-Based Awards

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)(2)			Estimated Future Payouts Under Equity Incentive Plan Awards				
Name	Grant Date	Approval Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)(5)
John W. Somerhalder II	02/03/14			1,072,464	2,144,928					
	02/10/14(3)	02/04/14	—			30,510	61,020	122,040		3,326,200
	02/10/14(4)	02/04/14					22,820			1,046,069
Andrew W. Evans	02/03/14			363,635	727,270					
	02/10/14(3)	02/03/14	—			8,975	17,950	35,900	—	978,455
	02/10/14(4)	02/03/14					6,710			307,586
Henry P. Linginfelter	02/03/14	02/03/14		355,736	711,472					
	02/10/14(3)	02/03/14	—			7,635	15,270	30,540	—	832,368
	02/10/14(4)	02/03/14					5,710			261,746
Paul R. Shlanta	02/03/14	02/03/14		247,029	494,058					
	02/10/14(3)	02/03/14	—			4,700	9,400	18,800	—	512,394
	02/10/14(4)	02/03/14					3,510			160,898
Peter I. Tumminello	02/03/14	02/03/14		391,250	443,750					
	02/10/14(3)	02/03/14	—			2,395	4,790	9,580		261,103
	02/10/14(4)	02/03/14					1,790			82,054

(1) Reflects annual incentive opportunity for 2014 under the annual incentive plan and the OPIP.

(2) The annual incentive award includes a corporate component and a business unit component. The threshold payout amount for the 2014 corporate component was as follows: $319,937 for Mr. Somerhalder; $107,903 for Mr. Evans; $105,559 for Mr. Linginfelter; and $73,693 for Mr. Shlanta. The 2014 business unit component consisted of a series of differently-weighted metrics and could pay out anywhere from 0% to 200% of target. Accordingly, the business unit component did not include a threshold amount.

The annual incentive award for Mr. Tumminello is not subject to a true maximum as it is based on an incentive pool. Please refer to page 53 for more detail.

(3) Reflects performance share units granted under the OPIP with a 36-month performance measurement period that ends December 31, 2016. These units are payable 50% in shares of AGL Common Stock and 50% in cash.

(4) Reflects restricted stock units granted under the OPIP with a 12-month performance measurement period that ended December 31, 2014.

(5) Reflects the aggregate grant date fair value of stock awards, which are based on target-level award and computed in accordance with FASB ASC Topic 718. The assumptions used in calculating these amounts are incorporated by reference to Note 7—"Stock-Based Compensation" to the financial statements in our annual report on Form 10-K filed with the SEC on February 12, 2015.

Outstanding Equity Awards at Fiscal Year End

The following table presents information concerning outstanding equity awards held by the named executive officers as of December 31, 2014.

Outstanding Equity Awards at 2014 Fiscal Year End

		Option Awards					Stock Awards			
Name		Date of Grant	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexer-cised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested (#)	Market Value of Shares or Units of Stock that Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vest (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, or Units or Other Rights that Have Not Vested ($)
John W. Somerhalder II		03/03/06	200,000	—	35.83	03/03/16	—	—	—	—
		01/30/07	65,700	—	38.96	01/30/17	—	—	—	—
		02/05/08	51,900	—	39.03	02/05/18	—	—	—	—
		02/03/09	66,800	—	31.09	02/03/19	—	—	—	—
	(1)	02/07/11	—	—	—	—	5,450	203,939	—	—
	(2)	02/17/12	—	—	—	—	—	—	55,850	2,526,838
	(5)	02/05/13	—	—	—	—	—	—	24,150	1,010,436
	(6)	02/05/13	—	—	—	—	—	—	56,340	3,071,093
	(7)	02/10/14							22,820	1,046,069
	(8)	02/10/14							61,020	3,326,200
Andrew W. Evans	(1)	02/07/11	—	—	—	—	1,807	67,618	—	—
	(2)	02/17/12	—	—	—	—	—	—	13,880	627,977
	(3)	07/30/12	—	—	—	—	14,750	600,030	—	—
	(5)	02/04/13	—	—	—	—	—	—	6,000	251,040
	(6)	02/04/13	—	—	—	—	—	—	14,000	763,140
	(7)	02/10/14							6,710	307,586
	(8)	02/10/14							17,950	978,455
Henry P. Linginfelter	(1)	02/07/11	—	—	—	—	1,767	66,121	—	—
	(2)	02/17/12	—	—	—	—	—	—	13,570	613,952
	(3)	07/30/12	—	—	—	—	14,750	600,030	—	—
	(4)	02/04/13	—	—	—	—	—	—	5,870	245,601
	(5)	02/04/13	—	—	—	—	—	—	13,690	746,242
	(7)	02/10/14							5,710	261,746
	(8)	02/10/14							15,270	832,368

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		Option Awards					Stock Awards			
Name		Date of Grant	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexer- cised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested (#)	Market Value of Shares or Units of Stock that Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vest (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, or Units or Other Rights that Have Not Vested ($)
Paul R. Shlanta		02/05/08	8,700	—	39.03	02/05/18	—	—	—	—
		02/03/09	11,840	—	31.09	02/03/19	—	—	—	—
	(1)	02/07/11	—	—	—	—	907	33,940	—	—
	(2)	02/17/12	—	—	—	—	—	—	8,600	389,092
	(4)	02/04/13	—	—	—	—	—	—	3,720	155,645
	(5)	02/04/13	—	—	—	—	—	—	8,670	472,602
	(7)	02/10/14							3,510	160,898
	(8)	02/10/14							9,400	512,394
Peter I. Tumminello		01/30/07	4,400	—	38.96	01/30/17	—	—	—	—
		02/05/08	3,500	—	39.03	02/05/18	—	—	—	—
		02/03/09	4,970	—	31.09	02/03/19	—	—	—	—
	(1)	02/07/11	—	—	—	—	683	25,558	—	—
	(2)	02/17/12	—	—	—	—	—	—	4,380	198,166
	(3)	07/30/12	—	—	—	—	14,750	600,030	—	—
	(4)	02/04/13	—	—	—	—	—	—	1,890	79,078
	(5)	02/04/13	—	—	—	—	—	—	4,420	240,934
	(6)	05/03/13	—	—	—	—	3,046	133,689	—	—
	(7)	02/10/14							1,790	82,054
	(8)	02/10/14							4,790	261,103

(1) Restricted stock units having satisfied criteria for the applicable performance measurement period, converted into an equal number of shares of restricted stock and vest at the rate of one-third per year, with vesting dates on March 1, 2013, March 1, 2014 and March 1, 2015.

(2) Performance share unit awards have a performance measurement period related to the Company's RTSR, with the measurement period ending on December 31, 2014. Awards shall be payable 50% in shares of AGL Resources common stock and 50% in cash. The RTSR as of December 31, 2014 results in a payout percentage of 83%.

(3) Reflects restricted stock awards granted under the OPIP with a three-year cliff vesting requirement.

(4) Restricted stock units having satisfied criteria for the applicable performance measurement period, converted into an equal number of shares of restricted stock and vest at the rate of one-third per year, with vesting dates on March 1, 2015, March 1, 2016 and March 1, 2017.

(5) Performance share unit awards have a performance measurement period related to the Company's RTSR, with the measurement period ending on December 31, 2015. Awards shall be payable 50% in shares of AGL Resources common stock and 50% in cash.

(6) Reflects restricted stock award granted under the OPIP with a three-year ratable vesting requirement.

(7) Restricted stock units having a performance measurement period related to the Company's EBITDA, with the measurement period ended December 31, 2014.

(8) Performance share unit awards have a performance measurement period related to the RTSR, with the measurement period ending on December 31, 2016. Awards shall be payable 50% in shares of AGL Resources common stock and 50% in cash.

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Option Exercises and Stock Vested

The following table presents information concerning stock options exercised by the named executive officers in 2014 and stock awards held by our named executive officers that vested in 2014.

2014 Stock Option Exercises and Stock Vested

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)(1)	Value Realized on Vesting ($)(1)
John W. Somerhalder II	—	—	36,842	1,779,015
Andrew W. Evans			13,332	649,280
Henry P. Linginfelter	26,900	384,161	13,037	634,917
Paul R. Shlanta	20,200	294,962	6,944	339,270
Peter I. Tumminello			6,875	342,770

(1) Represents the number of shares that vested in 2014 and the aggregate value of such shares based upon the fair market value of our common stock on the applicable vesting date.

Pension Benefits

The table below shows the present value of accumulated benefits payable to each of the named executive officers, including the number of years of service credited to each such named executive officer under our Pension Plan and Excess Plan, and, for Mr. Somerhalder, under terms set forth in an individual agreement. Assumptions used in the calculations are set forth in a table below the footnotes to the following table.

2014 Pension Benefits

Name	Plan Name(1)(2)	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
John W. Somerhalder II	Pension Plan	9	318,155	—
	Excess Plan	9	1,978,387	—
	Individual Agreement(3)	9(4)	731,925	—
Andrew W. Evans	Pension Plan	13	331,697	—
	Excess Plan	13	634,336	—
Henry P. Linginfelter	Pension Plan	34	763,585	—
	Excess Plan	34	702,190	—
Paul R. Shlanta	Pension Plan	17	503,397	—
	Excess Plan	17	771,334	—
Peter I. Tumminello	Pension Plan	11	295,249	—
	Excess Plan	11	579,371	—

(1) The AGL Resources Inc. Retirement Plan, which we refer to as the Pension Plan, is a broad-based, tax-qualified defined benefit plan. Generally, all of our union employees who have a hire date on, or before, December 31, 2012, and all of our non-union employees who have a hire date on, or before, December 31, 2011 are eligible to participate in the Pension Plan, upon completion of one year of service and attainment of age 21. Plan benefits are determined, generally, by a "career average" earnings formula. Generally, the Pension Plan provides that the term "compensation" means base pay, overtime and bonuses. Benefits vest upon completion of five years of service. A participant's accrued benefit is calculated based upon the normal form of benefits for that participant, as of the date the participant will reach the Pension Plan's normal retirement age of 65. The normal form of benefits for a participant who is single is a life annuity. The normal form for a married participant is a joint and 50% survivor annuity. The Pension Plan provides for the payment of benefits in other forms, if the participant so elects. These other forms include various annuities, and (for a broad class of employees, including the named executive officers) only in cases where a participant's benefit is less than $10,000, a single lump sum payment. Other employee groups may elect an unlimited lump sum. A participant may elect to receive benefits earlier than normal retirement age, once the participant has reached the early retirement age of 55. If a participant elects to commence benefits earlier than normal retirement age, the monthly payments will be reduced to reflect the fact that payments may continue over a longer period of time than if the employee had retired at normal retirement age. If the participant satisfies the Pension Plan's requirements for early retirement (age 55 with 5 years of service), the reduced amount is subsidized so that the reduction from the full normal retirement benefit is less severe than a full actuarial reduction. If the participant does not satisfy the early retirement criteria, the reduced payments represent the actuarial equivalent of the full normal retirement benefit.

(2) The AGL Resources Inc. Excess Benefit Plan, which we refer to as the Excess Plan, is a non-qualified, and unfunded, defined benefit plan designed for the benefit of a select group of management or highly compensated employees. Specifically, the Excess Plan is available to our employees who have a hire date on, or before, December 31, 2011, who are adversely affected by limitations set forth in the U.S. tax code, imposed on benefits under a tax-qualified plan, such as the Pension Plan. Benefits under the Excess Plan are calculated pursuant to a formula that first determines what the participant's benefit would be under the Pension Plan, but for the imposition of the U.S. tax code limits and then subtracts from that figure, the amount the participant will actually be entitled to under the Pension Plan. Benefits under the Excess Plan are paid in the same forms available under the Pension Plan, and are distributed at the later of separation from service or age 62.

(3) Mr. Somerhalder's individual agreement provides for one additional year of benefit accrual credit under the Pension Plan and Excess Plan for each year of service completed, up to a maximum of five additional years.

(4) In accordance with the terms of Mr. Somerhalder's individual agreement, a maximum of five years of credited service is used in this calculation.

Pension Benefit Assumptions

We used the following assumptions in calculating the present value of accumulated benefits:

• Retirement age:	Earliest unreduced
• Payment form:	Life annuity
• Discount rate:	4.20% at 12/31/2014
• Postretirement mortality:	RP-2014 mortality table, backed up to 2007 by Scale MP2014 and projected forward with the Mercer SSA intermediate alternative mortality improvement scale.
• Salary scale:	None
• Preretirement decrements: (mortality, withdrawals, disability)	None

Nonqualified Deferred Compensation

The table below relates to and describes compensation deferred by named executive officers under our Nonqualified Savings Plan.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($)(1)	Registrant Contributions in Last FY ($)(2)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($)(3)
John W. Somerhalder II	202,340	131,521	420,564	—	2,621,909
Andrew W. Evans	80,652	50,312	53,979	—	1,080,848
Henry P. Linginfelter	77,973	46,730	55,767	—	932,252
Paul R. Shlanta	53,265	32,714	106,214	—	1,328,058
Peter I. Tumminello	47,034	30,572	69,360	—	1,690,643

(1) All amounts set forth in this column are included in the Summary Compensation Table in the Salary column.

(2) All amounts set forth in this column represent Company contributions to our Nonqualified Savings Plan and are included in the Summary Compensation Table in the All Other Compensation column.

(3) Amounts set forth in this column for each named executive officer include amounts previously reported in the Summary Compensation Table, in the previous years when earned if that officer's compensation was required to be disclosed in a previous year. Amounts previously reported in such years include previously earned, but deferred, salary and annual incentive and Company matching contributions. This total reflects each named executive officer's deferrals, matching contributions and investment experience.

The Nonqualified Savings Plan allows eligible employees to defer up to 75% of base salary and up to 100% of annual incentive pay as before-tax contributions. The timing restrictions for contribution deferral elections are intended to comply with Section 409A of the U.S. tax code, as well as other applicable tax code provisions. For Employees who participate in our pension plan, including the named executive officers, the Company matches contributions at a rate of 65% of participant contributions, up to the first 8% of the participant's covered compensation. However, matching contributions under the Nonqualified Savings Plan are offset by the maximum matching contributions the participant could receive under our tax-qualified Retirement Savings Plus Plan. Each participant in the Nonqualified Savings Plan has a plan account, which represents a bookkeeping entry reflecting contributions and earnings/losses on the actual performance of the participant's notional investments. Participants are always 100% vested in their own contributions and vest in employer matching contributions over a three-year period according to a vesting schedule. The vesting associated with employer matching contributions is based upon employment service with the Company and is not subject to vesting based upon when the contribution itself was made. Distributions of a participant's account balance occur following a termination of employment. Participants have the option of taking distributions, following termination of employment, in the following forms: (i) a single lump sum cash payment; (ii) a lump sum cash payment of a portion of the participant's account, with the remainder distributed in up to ten equal annual installments; or (iii) between one and ten equal annual installments. The notional investment choices under the Nonqualified Savings Plan are similar to the investment choices in the Retirement Savings Plus Plan.

Potential Payments upon Termination or Change in Control

We have entered into certain agreements and maintain certain plans that will require us to provide compensation and benefits to our named executive officers in the event of a termination of employment following a change in control of our Company. We do not otherwise maintain any agreement, plan or practice that specifically provides for compensation to a named executive officer upon termination of employment. The appropriate amount of compensation payable to each named executive officer in each relevant situation is listed in the tables below. Footnotes relating to all of these tables follow the last table on page 72.

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The following table describes the potential payments upon termination of employment with the Company for John W. Somerhalder II, our chairman, president and chief executive officer.

Executive Benefits and Payments Upon Termination(1)	Potential Payments Upon Termination Other Than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)	Death or Disability (6)
Cash Severance:					
Base Salary	$ —	(3)	$ —	$ 1,949,934	$ —
Short-term Incentive	(2)	(3)	—	2,633,275	1,352,563
Long-term Incentives:					
Unvested Restricted Stock	(2)	(3)	—	1,613,495	627,126
Unvested Restricted Stock Units	(2)	(3)	—	1,243,918	277,290
Unvested Performance Share Units	(2)	(3)	—	6,200,512	(6)
Unvested Stock Options	(2)	—	—	—	—
Benefits & Perquisites:					
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	114,724	(6)
Disability Benefits	—	—	—	—	(6)
Death Benefit	—	—	—	—	(6)
Accrued Vacation Pay	7,500	7,500	7,500	7,500	7,500
Outplacement Assistance	—	(3)	—	243,742	—
Sub-Total:	(2)	(3)	7,500	14,007,100	(6)
280G Cutback:	N/A	N/A	N/A	N/A	N/A
TOTAL:	(2)	(3)	$ 7,500	$ 14,007,100	(6)

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The following table describes the potential payments upon termination of employment with the Company for Andrew W. Evans, our executive vice president and chief financial officer.

Executive Benefits and Payments Upon Termination(1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)	Death or Disability (6)
Cash Severance:					
Base Salary	$ —	(3)	$ —	$ 1,118,876	$ —
Short-term Incentive:	—	—	—	884,056	462,102
Long-term Incentives:					
Unvested Restricted Stock	—	—	—	1,229,563	803,720
Unvested Restricted Stock Units	—	—	—	365,762	81,534
Unvested Performance Share Units	—	—	—	1,591,510	(6)
Unvested Stock Options	—	—	—	—	—
Benefits & Perquisites:					
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	54,572	(6)
Disability Benefits	—	—	—	—	(6)
Death Benefit	—	—	—	—	(6)
Accrued Vacation Pay	4,303	4,303	4,303	4,303	4,303
Outplacement Assistance	—	(3)	—	139,860	—
Sub-Total:	4,303	(3)	4,303	5,388,502	(6)
280G Cutback:	N/A	N/A	N/A	(416,466)	N/A
TOTAL:	$ 4,303	(3)	$ 4,303	$ 4,972,036	(6)

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The following table describes the potential payments upon termination of employment with the Company for Henry P. Linginfelter, our executive vice president, distribution operations.

Executive Benefits and Payments Upon Termination(1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)	Death or Disability (6)
Cash Severance:					
Base Salary	$ —	(3)	$ —	$ 1,094,572	$ —
Short-term Incentive	(2)	—	—	1,005,939	594,383
Long-term Incentives:			—		
Unvested Restricted Stock	(2)	—	—	1,220,297	800,339
Unvested Restricted Stock Units	(2)	—	—	311,252	83,159
Unvested Performance Share Units	(2)	—	—	1,514,652	(6)
Unvested Stock Options	—	—	—	—	—
Benefits & Perquisites:					
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	95,813	(6)
Disability Benefits	—	—	—	—	(6)
Death Benefit	—	—	—	—	(6)
Accrued Vacation Pay	8,948	8,948	8,948	8,948	8,948
Outplacement Assistance	—	(3)	—	136,822	—
Sub-Total:	(2)	(3)	8,948	5,388,295	(6)
280G Cutback:	N/A	N/A	N/A	(988,265)	N/A
TOTAL:	(2)	(3)	$ 8,948	$ 4,400,030	(6)

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The following table describes the potential payments upon termination of employment with the Company for Paul R. Shlanta, our executive vice president, general counsel and chief ethics and compliance officer.

Executive Benefits and Payments Upon Termination(1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)	Death or Disability (6)
Cash Severance:					
Base Salary	$ —	(3)	$ —	$ 898,286	(6)
Short-term Incentive	(2)	(3)	—	730,466	435,470
Long-term Incentives:					
Unvested Restricted Stock	(2)	(3)	—	252,199	96,742
Unvested Restricted Stock Units	(2)	(3)	—	191,330	42,651
Unvested Performance Share Units	(2)	(3)	—	954,652	(6)
Unvested Stock Options	—	—	—	—	—
Benefits & Perquisites:					
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	107,691	(6)
Disability Benefits	—	—	—	—	(6)
Death Benefit	—	—	—	—	(6)
Accrued Vacation Pay	13,172	13,172	13,172	13,172	13,172
Outplacement Assistance	—	(3)	—	112,286	—
Sub-Total:	(2)	(3)	13,172	3,260,082	(6)
280G Cutback:	N/A	N/A	N/A	(637,936)	N/A
TOTAL:	(2)	(3)	$ 13,172	$ 2,622,146	(6)

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The following table describes the potential payments upon termination of employment with the Company for Peter I. Tumminello, executive vice president, wholesale services and president, Sequent.

Executive Benefits and Payments Upon Termination(1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Death or Disability (6)
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)	
Cash Severance:					
Base Salary	$ —	(3)	$ —	$ 732,022	$ —
Short-term Incentive	—	(3)	—	4,245,552	3,550,000
Long-term Incentives:					
Unvested Restricted Stock	—	(3)	—	1,110,368	751,733
Unvested Restricted Stock Units	—	(3)	—	97,573	21,751
Unvested Performance Share Units	—	(3)	—	486,411	(6)
Unvested Stock Options	—	—	—	—	—
Benefits & Perquisites:					
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	74,596	(6)
Disability Benefits	—	—	—	—	(6)
Death Benefit	—	—	—	—	(6)
Accrued Vacation Pay	—	—	—	—	—
Outplacement Assistance	—	(3)	—	91,503	—
Sub-Total:	(2)	(3)	—	6,838,025	(6)
280G Cutback:	N/A	N/A	N/A	N/A	N/A
TOTAL:	(2)	(3)	(4)	$ 6,838,025	(6)

Below is a description of the assumptions that we used in creating the tables above. Unless otherwise noted, the descriptions of the payments below are applicable to all of the above tables relating to potential payments upon termination or change in control.

Notes to Potential Payments upon Termination or Change in Control Tables

(1) For purposes of this analysis, we assumed the executive's compensation as current base salary, target annual incentive opportunity and target long-term incentive opportunity, each as of December 31, 2014. Each column assumes the named executive officer's date of termination is December 31, 2014 and the price per share of our common stock on the date of termination is $54.51.

(2) If the executive leaves voluntarily prior to retirement eligibility, compensation stops as of the termination date. All outstanding and unvested long-term incentive awards would be forfeited. No further benefits would be earned under ERISA-qualified plans. Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination and at

least six months following the date of termination, or later if the executive had timely elected. Prorated accrued and unused vacation would be paid. If the executive was retirement-eligible at the time of voluntary termination and elected to retire, in addition to commencing retirement benefits, he would be entitled to a prorated annual incentive under the annual incentive plan, conditioned on the Company's satisfaction of applicable performance goals, and prorated vesting of certain long-term incentive awards, conditioned on the Company's satisfaction of applicable performance goals. The satisfaction of such goals would be measured at the end of the performance period, and any payment would be made at that time. Due to the future performance measurement, the value of the unvested performance-based awards is not currently calculable.

(3) If the executive is terminated without "cause," a severance agreement may be executed based upon the facts and circumstances of the termination and in exchange for a release of any future liabilities which might otherwise be claimed by the executive. Due to the wide range and variety of circumstances, there is no preset policy governing involuntary severance compensation. However, any terms of such a special agreement would be subject to the review and approval of the Compensation Committee. Upon such a termination, no further benefits would be earned under ERISA-qualified plans. Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination and at least six months following the date of termination, or later if the executive had timely elected. Outstanding long-term incentive awards would be forfeited and annual incentive would not be payable.

The prorated value of accrued but unused vacation would be paid.

(4) If the executive is terminated for "cause," compensation stops as of the termination date. All outstanding long-term incentive awards would be forfeited. No further benefits would be earned under ERISA-qualified plans. Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination and at least six months following the date of termination, or later if the executive had timely elected. The prorated value of accrued but unused vacation would be paid.

(5) If the executive is terminated without cause, or resigns for good reason, generally, within two years of a change in control (as described below) the terms and conditions described below under "Payments upon a Termination in connection with a Change in Control" would apply.

(6) If the executive's employment terminates as a result of death, a death benefit would be paid to the executive's estate in an amount equal to the lesser of one year's base salary or $250,000 from a Company-sponsored plan that covers all employees. That plan does not discriminate in favor of executives, or highly compensated employees. Upon a determination of long-term disability, payments would be made, based on the level of coverage elected and paid for by the executive, under our group disability plan. Our disability plan is also a plan that does not discriminate in favor of executives, or highly compensated employees. In the event of death or disability, the executive (or the executive's designated beneficiary) also would receive a prorated annual incentive under the annual incentive plan,

conditioned on the Company's satisfaction of applicable performance goals, and prorated vesting of all unvested stock options. In addition, long-term incentive awards would vest on a pro rata basis with performance conditioned on the Company's satisfaction of applicable performance goals. The satisfaction of such goals would be measured at the end of the performance period, and any payment made at that time. Due to the future performance measurement, the value of the unvested performance-based awards is not currently calculable.

Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination, or later if the executive has so elected. The prorated value of accrued but unused vacation would be paid.

Payments upon a Termination in connection with a Change in Control

Each of the named executive officers has a continuity agreement with us, as referenced on page 40 in the Compensation Discussion and Analysis. The purpose of these agreements is to retain key management personnel and assure continued productivity of such personnel in the event of a change in control of our Company.

The continuity agreements define a "change in control" to generally mean the occurrence of any of the following events:

- the acquisition by a person or group of persons of more than 50% of our voting securities, based upon total fair market value or total voting power;
- the acquisition, within a twelve-month period by a person or group of more than 35% of the total voting power of the stock of the Company;
- the replacement, during a twelve-month period of a majority of members of our board of directors with directors not endorsed by a majority of the incumbent directors; or
- the acquisition by a person or group of assets of the Company, having a fair market value of at least 50% of the fair market value of all Company assets, immediately before such acquisition.

Benefits are only provided under the continuity agreements in the event of a termination without "cause" or resignation for "good reason" within two years after a change in control, or after our announcement of our intention to engage in a transaction that is expected to result in a change in control, provided that a change in control actually occurs. No benefits are provided if a change in control does not occur, for any terminations that occur outside these periods, or for any termination for cause, resignation without good reason, or termination due to death or disability whenever they occur. "Cause" includes failure to perform duties and responsibilities, willful fraud, dishonesty or malfeasance that results in material harm to the Company, or a plea of guilty or no contest to a felony. "Good reason" includes a material diminution of position, duties or responsibilities; material diminution of base salary or annual incentive opportunity (unless consistent with a diminution for all executives at a comparable level), a material breach by the Company of any agreement under which the executive provides services, or a material change in the geographic location (at least 50 miles) of the executive's primary employment location.

An officer who has a qualifying termination event during the change in control period would be entitled to:

- a severance benefit equal to two times the sum of his or her base salary plus the average annual incentive compensation actually paid during the three years prior to the year of the qualifying termination;

- a prorated annual incentive compensation payment for the year of the qualifying termination, based on the number of days the named executive officer was employed by us during that year and the greater of the target annual incentive for the officer or the incentive that would be paid based upon actual performance through the date of termination;
- two-year continuation of medical, dental and life insurance benefits;
- potential vesting of long-term incentive compensation, pursuant to the terms of the plan the awards were granted under; and
- outplacement assistance.

The executives may also receive reimbursement of legal fees in connection with the enforcement of payments under the continuity agreements.

If the payments under the continuity agreements and under any other compensation arrangement with the Company, were to exceed three times the base amount permitted under Section 280G(b)(3) of the U.S. tax code, the payments would be reduced and payable only to the maximum amount which could be paid without the imposition of the excise tax under Section 4999 of the U.S. tax code, unless the officer's payment of such excise taxes and all other applicable taxes on the full payment amount would result in him or her receiving a greater resulting amount, net of such taxes. For 2014, calculations performed on amounts potentially payable if severance under the continuity agreements was triggered reflect that a reduction (or "cutback") would be more beneficial to Messrs. Evans, Linginfelter and Shlanta than payment of the extra taxes but not for Messrs. Somerhalder and Tumminello. Where applicable the tables reflect the amount of the required cutback and the net payments payable after the cutback was applied.

The continuity agreements contain covenants on the part of the executive relating to the maintenance of our confidential information and that require the executive to refrain from taking action that disparages the reputation of the Company or any of its subsidiaries or, for a period of 24 months following a qualifying termination, from soliciting employees of the Company or its subsidiaries.

Summary of Potential Payments upon a Change in Control

The following table summarizes the value of the payments that each of our named executive officers would receive as a result of the vesting of long-term incentive awards if a change in control had occurred on December 31, 2014, the awards were *not* assumed or substituted by the successor company, and the executive did *not* incur a termination of employment. The amounts in the table exclude the value of long-term incentive awards that were vested by their terms on December 31, 2014. If the awards were assumed or substituted by the successor company in such an instance, then the awards will continue to vest pursuant to their original terms and no value would be received by our named executive officers.

	John W. Somerhalder II	Andrew W. Evans	Henry P. Linginfelter	Paul R. Shlanta	Peter I. Tumminello
Stock Options	$ —	$ —	$ —	$ —	$ —
Unvested Restricted Stock	1,613,495	1,229,563	1,220,297	252,199	1,110,368
Unvested Restricted Stock Units	1,243,918	365,762	311,252	191,330	95,573
Unvested Performance Share Units	6,200,512	1,591,510	1,514,652	954,652	486,411
Total	$ 9,057,925	$ 3,186,835	$ 3,046,201	$ 1,398,181	$ 1,692,352

Each column assumes the change in control had occurred on December 31, 2014 and the price per share of our common stock on the date of termination is $54.51. All awards were granted under our OPIP, which provides that such awards will only become vested and non-forfeitable immediately following the change in control (absent a qualifying termination of employment), if the surviving entity fails to assume or substitute the awards.

Equity Compensation Plan Information

The following table provides information as of December 31, 2014, with respect to the shares of our common stock that may be issued under our existing equity compensation plans:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)(1)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a)) (c)(1)
Equity compensation plans approved by security holders	1,023,692	$ 37.17	2,872,272
Equity compensation plans not approved by security holders	0	0	1,551,040
Total	1,023,692	—	4,423,312

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(1) Includes shares issuable as follows:

Name of Plan	Approved by Security Holders	Active/ Inactive Plan (a)	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Outstanding Options)
Omnibus Performance Incentive Plan, as Amended and Restated (OPIP)	□	Active	587,292	2,411,295(b)
Long-Term Incentive Plan (1999)	□	Inactive	436,400	0
2006 Directors Plan	□	Active	N/A	38,413
Employee Stock Purchase Plan	□	Active	N/A	422,564
Subtotal—Approved Plans			1,023,692	2,872,272
Assumed Nicor Inc. Plan Shares under OPIP(c)	No	Active	0	1,551,040
Subtotal—Not Approved Plans			0	1,551,040
Total	—	—	1,023,692	4,423,312

(a) No further grants will be made under the inactive plan except for reload options that may be granted under outstanding option agreements under the 1999 Long-Term Incentive Plan.

(b) The Omnibus Performance Incentive Plan, as Amended and Restated (OPIP), includes separate pools of shares for share counting purposes. The amount shown in the table above includes 1,000,000 shares which are available for future issuance as awards pursuant to stock options or stock appreciation rights under the “Remainder Reserve.” If issued pursuant to full value awards (which include awards other than stock options or stock appreciation rights), only 200,000 shares could be issued under the Remainder Reserve. In such event, the number of securities remaining available for future issuance under the OPIP, the subtotal for approved plans, and the total each would decrease by 800,000 shares.

(c) Pursuant to the terms of the OPIP, which was approved by our shareholders, shares available under a shareholder-approved plan of a company acquired by the Company (as appropriately adjusted to reflect the transaction) may be issued under the OPIP pursuant to awards granted to individuals who were not employees of the Company or a related company immediately before such transaction. These assumed shares do not count against the maximum share limitation specified in the OPIP. Such assumption of shares in a merger does not require approval of our shareholders under the rules of the New York Stock Exchange or otherwise. The shares designated as “Assumed Nicor Inc. Plan Shares” in the table above remained available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, at the time of our merger with Nicor Inc. These shares were assumed under the OPIP and are available for future issuance to persons who were not employees of the Company or a related company immediately prior to our merger with Nicor Inc.

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PROPOSAL 3—ADVISORY VOTE ON EXECUTIVE COMPENSATION

In accordance with Section 14A of the Exchange Act, each year, our shareholders have the opportunity to vote to approve, on an advisory (non-binding) basis, the compensation of our named executive officers as disclosed in our annual proxy statement in accordance with the SEC's rules.

As described in detail under the heading "Executive Compensation—Compensation Discussion and Analysis," our executive compensation programs are designed to attract, motivate and retain our named executive officers, who are critical to our success. Under these programs, our named executive officers are rewarded for the achievement of specific annual, long-term and strategic goals, corporate goals and the realization of increased shareholder value. Please read the "Compensation Discussion and Analysis" beginning on page 37 for additional details about our executive compensation programs, including information about the fiscal year 2014 compensation of our named executive officers.

The Compensation Committee reviews the compensation programs for our named executive officers in an effort to achieve the desired goals of aligning our executive compensation structure with Company performance, our shareholders' interests and current market practices. We believe that this alignment motivates our executives to achieve our key financial and strategic goals, creating long-term shareholder value.

We are asking our shareholders to indicate their support for our named executive officer compensation as described in this proxy statement. This proposal, commonly known as a "say-on-pay" proposal, gives our shareholders the opportunity to express their views on our named executive officers' compensation. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers and the philosophy, policies and practices described in this proxy statement. Accordingly, we are asking our shareholders to vote "FOR" the following resolution at the annual meeting:

> "RESOLVED, that the Company's shareholders approve, on an advisory basis, the compensation of the named executive officers, as disclosed in the Company's Proxy Statement for the 2015 Annual Meeting of Shareholders pursuant to the compensation disclosure rules of the Securities and Exchange Commission, including the Compensation Discussion and Analysis, the accompanying compensation tables and the related narrative disclosure."

The say-on-pay vote is advisory and therefore not binding on the Company, the Compensation Committee or our board of directors. Our board of directors and our Compensation Committee value the opinions of our shareholders. Following the annual meeting, we will consider our shareholders' feedback and the Compensation Committee will evaluate whether any actions are necessary to address this feedback.

THE BOARD OF DIRECTORS RECOMMENDS THAT SHAREHOLDERS VOTE "FOR" THE APPROVAL OF THE COMPENSATION OF OUR NAMED EXECUTIVE OFFICERS, AS DISCLOSED IN THIS PROXY STATEMENT.

PROPOSAL 4— APPROVAL OF AN AMENDMENT TO THE COMPANY'S AMENDED AND RESTATED ARTICLES OF INCORPORATION TO PROVIDE HOLDERS OF AT LEAST 25% OF THE VOTING POWER OF ALL OUTSTANDING SHARES ENTITLED TO VOTE THE RIGHT TO CALL A SPECIAL MEETING OF SHAREHOLDERS

The board is requesting that shareholders approve an amendment to article VIII of the Company's amended and restated articles of incorporation so that shareholders of record holding, in a net long position continuously for at least one year, not less than 25% of all outstanding shares entitled to vote will have the right to call a special meeting of shareholders, subject to procedures set forth in section 1.3 of the Company's bylaws. A shareholder's "net long position" is the amount of shares in which the shareholder holds a positive (i.e., "long") economic interest, reduced by the amount of shares in which the shareholder holds a negative (i.e., "short") economic interest.

Currently, article VIII of the Company's amended and restated articles of incorporation permits holders of not less than 100% of the shares of the Company's then outstanding common stock to call a special meeting of shareholders. Similarly, section 1.3 of the Company's bylaws, as amended, requires the Company to hold a special meeting of shareholders upon delivery to the Company's Corporate Secretary of a signed and dated written demand for the meeting from holders of 100% of the votes entitled to be cast on any issues proposed to be considered at the proposed special meeting of shareholders.

The proposed amendment would amend article VIII of the Company's amended and restated articles of incorporation as set forth below, with the changes noted:

> At any time in the interval between annual meetings of shareholders, special meetings of the shareholders may be called by the Chairman of the Board of Directors, the President, the Board of Directors or the Executive Committee by vote at a meeting, by a majority of Directors in writing without a meeting, or by the holders of not less than ~~100%~~ 25% of the shares of Common Stock then outstanding and entitled to vote, who held that amount of shares in a net long position continuously for at least one year. The procedure to be followed by shareholders seeking to call a special meeting of shareholders and the methodology for determining the percentage of votes entitled to be cast by the shareholders seeking to call a special meeting of shareholders (including without limitation the calculation of the amount of a net long position or other limitations or conditions) shall be as set forth in the Corporation's Bylaws.

The proposed amendment was approved by the board after careful review of the ongoing evolution of corporate governance practices. The board believes that lowering the required ownership threshold to request a special meeting to 25% strikes a balance between enhancing the rights of shareholders to call a special meeting and protecting against the risk that a small minority of shareholders, including shareholders with special interests, could require a special meeting resulting in financial expense, administrative burden and disruption to the Company's business. For each special meeting of shareholders, the Company would be required to provide each shareholder with notice and proxy materials, which results in significant expenses. Moreover, preparing for shareholder meetings requires significant attention of the Company's directors, officers and employees, diverting their attention from performing their primary function, which is to operate effectively the Company's business in the best interest of shareholders. Given these facts, the board believes that special meetings of shareholders should only be called to consider extraordinary matters that are of interest to a broad base of shareholders who cannot have their consideration delayed until the next annual meeting. By taking into account (a) the extent to which shareholders requesting a special meeting hedge their shares (or otherwise offset their economic exposure in their shares) and (b) the length of time those shares have been held, the “net long position” requirement ensures that shareholders seeking to exercise the right to call a special meeting have both a true economic and non-transitory interest in the Company. This length of ownership requirement is consistent with the SEC’s current rules affecting shareholder rights concerning annual and special shareholder meetings. Specifically, it is the same length of ownership requirement for determining a shareholder’s eligibility to submit a shareholder proposal for an annual or special shareholder meeting.

The board is committed to good governance practices and is interested in the views and concerns of the Company’s shareholders. The board will continue to maintain the Company’s existing governance mechanisms that afford management and the board the ability to respond to proposals and concerns of all shareholders, regardless of the level of share ownership.

If the proposed amendment to article VIII of the Company’s amended and restated articles of incorporation is approved by shareholders, it will become effective upon the filing of articles of amendment with the Georgia Secretary of State. The Company will file those articles of amendment promptly after the 2015 Annual Meeting. Following the effectiveness of the articles of amendment, the board will adopt amendments to section 1.3 of the Company’s bylaws including provisions dealing with the information required to be furnished with any special meeting request, the determination of the requesting shareholders’ net long position, the scope of business to be considered at any special meeting, and the date by which a special meeting must be held pursuant to any qualifying request.

THE BOARD OF DIRECTORS RECOMMENDS THAT SHAREHOLDERS VOTE “FOR” THE APPROVAL OF THE AMENDMENT OF THE COMPANY’S AMENDED AND RESTATED ARTICLES OF INCORPORATION.

PROPOSAL 5—SHAREHOLDER PROPOSAL: INDEPENDENT CHAIRMAN POLICY

The Company has received the following shareholder proposal. Pursuant to Rule 14a-8(l)(1) of the Exchange Act, the Company will provide the name, address and number of securities held by the proponents of this proposal to any shareholder upon receipt of a written or oral request. You may contact our Corporate Secretary for this information at AGL Resources Inc., Attn: Corporate Secretary, P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569.

The Company is not responsible for the contents of this proposal or supporting statement, both of which are quoted verbatim in italics below.

What is the proposal?

RESOLVED: That the stockholders of AGL Resources ("AGL" or "the Company") ask the board of directors to adopt a policy that, whenever possible, the board's chairman should be an independent director who has not previously served as an executive officer of the Company. The policy should be implemented so as not to violate any contractual obligation. The policy should also specify (a) how to select a new independent chairman if a current chairman ceases to be independent during the time between annual meetings of shareholders; and, (b) that compliance with the policy is excused if no independent director is available and willing to serve as chairman.

SUPPORTING STATEMENT

It is the responsibility of the Board of Directors to protect shareholders' long-term interests by providing independent oversight of management, including the Chief Executive Officer (CEO), in directing the corporation's business and affairs. Currently Mr. John Somerhalder is Chairman of the Board and CEO of our Company. We believe that this scheme may not adequately protect shareholders.

We believe that an independent Chairman who sets agendas, priorities and procedures for the board can enhance board oversight of management and help ensure the objective functioning of an effective board. We also believe that having an independent Chairman (in practice as well as appearance) can improve accountability to shareowners, and we view the alternative of having a lead outside trustee, even one with a robust set of duties, as not adequate to fulfill these functions.

A number of respected institutions recommend such separation. CalPERS' Corporate Core Principles and Guidelines state that "the independence of a majority of the Board is not enough"; "the leadership of the board must embrace independence, and it must ultimately change the way in which directors interact with management." In 2009 the Milstein Center at Yale School of management issued a report, endorsed by a number of investors and board members, which recommended splitting the two positions as the default provision for U.S. companies. A commission of The Conference Board stated in a 2003 report "Each corporation should give careful consideration to separating the offices of Chairman of the Board and CEO, with those two roles being performed by separate individuals. The Chairman would be one of the independent directors."

We believe that the recent economic crisis demonstrates that no matter how many Independent trustees there are on the Board, that Board is less able to provide independent oversight of the officers if the Chairman of that Board is also the CEO of the Company.

We, therefore, urge shareholders to vote FOR this proposal.

What does the board recommend?

THE BOARD OF DIRECTORS RECOMMENDS THAT YOU VOTE "AGAINST" THIS PROPOSAL FOR THE FOLLOWING REASONS:

The board has considered this proposal and believes that it is not in the best interests of the Company or its shareholders because (i) the board's existing leadership structure and composition provide effective independent oversight of management, (ii) the current leadership structure is working effectively and (iii) the proposal would unnecessarily limit the board's flexibility.

The board strongly believes that the Company's current leadership structure already achieves the independent leadership and effective management oversight sought by the proposal. Specifically:

- Currently, 14 of the 15 incumbent members of the board are independent, according to the criteria specified by applicable laws and regulations of the SEC, the listing standards of the New York Stock Exchange and the Company's Standards for Determining Director Independence.
- Under the Company's Corporate Governance Guidelines, if the Chairman is an executive officer or employee of the Company, then the board of directors shall appoint, from among the independent directors, a Lead Director. This has been the Company's policy since 2007. The Lead Director, appointed from among the board's independent directors, has significant authority and responsibilities as outlined on page 9 under the heading "Corporate Governance—Board Leadership Structure." Recognizing there may be a circumstance where a shareholder or other interested party's interest should be represented independent of management, a key responsibility of the Lead Director is to receive, review and, where necessary, act upon direct communications from shareholders and other interested parties. Mr. Arthur E. Johnson currently serves as our Lead Director.
- Non-management directors meet for a portion of each regular meeting in executive sessions chaired by the Lead Director with no members of management present. These executive sessions allow the board to review key decisions and discuss matters in a manner that is independent of the Chief Executive Officer and, where necessary, critical of the Chief Executive Officer and senior management.
- Each of the board's standing committees is chaired by an independent director and each of our Audit, Compensation and Nominating, Governance and Corporate Responsibility committees is comprised entirely of independent directors.

The board further believes that the current leadership structure is working effectively. Among other benefits, Mr. Somerhalder's role as Chief Executive Officer enables him, working with the Lead Director, to act as a bridge between management and the board, helping management and the board to act with a common purpose. Mr. Somerhalder's combined roles as Chief Executive Officer and Chairman promote unified leadership and direction for the Company. Mr. Somerhalder's knowledge of the day-to-day operations of the Company, perspective on competitive developments, understanding of shareholder interests, and relationships with business partners and employees allow him to provide effective leadership in his role as Chairman and Chief Executive Officer. Also, a combined Chairman and Chief Executive Officer role allows for more productive board meetings. The board believes the Company's strong financial performance and achievement of key strategic objectives demonstrates the effectiveness of the current leadership structure.

In view of our highly independent board structure and the Company's sound governance practices, the Company believes it is important to retain flexibility to adopt the most effective board leadership structure as the facts and circumstances warrant and to be able to select the director best suited to serve as Chairman. The proposal would create an unnecessary limitation on the board's flexibility and deprive the board of the opportunity to select the most qualified and appropriate individual to lead the board.

The board of directors recommends a vote **"AGAINST"** this proposal.

PROPOSAL 6—SHAREHOLDER PROPOSAL: GOALS FOR REDUCING GREENHOUSE GAS EMISSIONS

The Company has received the following shareholder proposal. Pursuant to Rule 14a-8(l)(1) of the Exchange Act, the Company will provide the name, address and number of securities held by the proponent of this proposal to any shareholder upon receipt of a written or oral request. You may contact our Corporate Secretary for this information at AGL Resources Inc., Attn: Corporate Secretary, P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569.

The Company is not responsible for the contents of this proposal or supporting statement, both of which are quoted verbatim in italics below.

What is the proposal?

Resolved*: Shareholders request that AGL Resources Inc. adopt quantitative company-wide goals for reducing GHG emissions from operations and products and report on its plans to achieve these goals by June 2015.*

Supporting Statement*: In 2013, the Intergovernmental Panel on Climate Change (IPCC), the world's leading scientific authority on climate change, released its fifth assessment report concluding that human-caused "warming of the climate system is unequivocal," with many of the impacts of warming already "unprecedented over decades to millennia."*

PWC states that to mitigate climate change the G20 needs to reduce its carbon intensity 6 percent per year and the global economy needs to decarbonize 6 percent per dollar GDP.

In 2012, the US experienced 11 such events resulting in an estimated $110 billion dollars in total damages and 377 fatalities. Drought in the U.S. Midwest in 2012 affected 80 percent of agricultural land, particularly corn and soybean production, costing approximately $30 billion dollars.

Analysis by McKinsey & Co., Deloitte Consulting, and Point380 found that U.S. companies could reduce emissions 3 percent annually between now and 2020 and realize savings up to $780 billion dollars.

Further analysis by Calvert, Ceres, WWF, and David Gardiner and Associates demonstrated that 53 Fortune 100 companies in 2012 alone reported that they are conservatively saving $1.1 billion dollars annually by decreasing their GHG emissions.

In Climate Action and Profitability: CDP S&P 500 Climate Change Report 2014, industry leaders in the S&P 500 that are actively managing and planning for climate change report:

- *18 percent higher return-on-equity than peers and 67 percent higher return-on-equity than companies who do not disclose on climate change.*
- *50 percent lower earnings volatility over past decade than low-ranking peers.*
- *21 percent stronger dividend growth than low-ranking peers.*

While over 500 businesses, including General Motors, Microsoft, and Nike signed the Climate Declaration that states, "Tackling climate change is one of America's greatest economic opportunities of the 21st century," AGL Resources Inc. is largely silent on emissions reductions.

The economic, business and societal impacts of climate change are of *paramount importance to investors. 767 institutional investors with $92 trillion dollars in assets under management have supported CDP's request to over 6,000 companies for disclosure of carbon emissions, reduction goals, and climate change strategies to address these risks.*

We recommend AGL Resources Inc. take into consideration the IPCC analysis and identified emission reduction targets as it sets its own scientific-based goal. We also recommend that AGL Resources Inc. consider renewable energy procurement as a strategy to achieve its emission reduction goals.

What does the board recommend?

THE BOARD OF DIRECTORS RECOMMENDS THAT YOU VOTE "AGAINST" THIS PROPOSAL FOR THE FOLLOWING REASONS:

The Company is engaged primarily in the distribution of natural gas to residential, commercial and industrial customers through a vast pipeline network. For more than a decade we have been committed to aggressively addressing greenhouse gas (GHG) emissions and have a demonstrated track record of success through participation in federal emission reduction programs, investing in system safety and reliability improvements that also lower emissions and through active participation in efforts to develop sound government policy for GHG emissions regulation.

Over the past 20 years, we have been an industry leader in pipeline replacement and repairs, spending over $1.5 billion in Georgia, New Jersey and Virginia to modernize over 2,500 miles of pipeline across our system. Through these safety and reliability activities, a core aspect of our business, we continue to achieve significant GHG emissions reductions. Further, as of 2015, we are embarking upon a nine-year $1.5 billion infrastructure replacement program in Illinois that will also reduce GHG emissions.

In addition to investing heavily to improve our distribution systems:

- The Company has been a leader in activities to reduce greenhouse gas emissions since 1993, when it joined the Environmental Protection Agency's Natural Gas STAR Program as an original participant. The Natural Gas STAR Program provides a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. The Company continuously implements changes to its operations, many of which yield measurable reductions in greenhouse gas and other emissions. During the first ten years of the Company's participation in Natural Gas STAR, it reduced cumulative emissions by over 700,000 mt CO2E.
- On January 14, 2015, the White House announced the Environmental Protection Agency's intention to expand the Natural Gas STAR Program's voluntary methane emissions program, and the Company intends to remain fully engaged with this initiative.
- The Company regularly works with its regulators—as well as advocates for legislation—to develop programs to accelerate the replacement of infrastructure, such as pipelines and valves, one of the significant benefits of which is to reduce direct fugitive emissions of methane. The Company's

efforts have been very successful—and were recently featured in the American Gas Association magazine as an example of industry best practices.

- The Company is one of seven in the natural gas value chain, and one of only two utilities, to form Our Nation's Energy Future (also known as "ONE Future"), which has the goal of reducing methane leak loss rates across the value chain to less than 1%, a level which all available science indicates is not only cost-effective and attainable, but the point at which natural gas becomes the unassailable fuel of choice from a climate perspective. The EPA cited the ONE Future initiative as one it is committed to continue to work with to develop and verify robust commitments to reduce methane emissions. The Company actively advocates for value chain-wide methane emission standards, and has met with representatives of the White House, Environmental Protection Agency, Department of Energy, and Federal Energy Regulatory Commission on this issue.

Because of these on-going Company efforts, our demonstrated commitment to GHG emissions reductions and the emergence of federal GHG regulations, the Board does not believe it is in the best interests of the Company, nor would it be an efficient use of Company resources, to establish, at this time, voluntary, quantitative GHG emission reduction goals for the Company's products and operations and issue a report by June 2015, regarding its plans to achieve these goals. The Board does not believe that the proposed report would add value to the Company's efforts in this area.

The board of directors recommends a vote **"AGAINST"** this proposal.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The Vanguard Group, Inc. was a beneficial owner of more than 5% of the Company's common stock during 2014. The Vanguard Group, Inc. or its subsidiaries ("Vanguard") served as the trustee and recordkeeper for the Birdsall Retirement Savings Plan, which was available to employees in our Tropical Shipping business. In September 2014, we sold our Tropical Shipping business. From January to September 2014, Vanguard was paid approximately $229,357 for trustee and recordkeeping services.

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SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors and certain of our officers, including executive officers, and any person who owns more than 10% of our common stock to file reports of initial common stock ownership and changes in common stock ownership with the SEC and the New York Stock Exchange. Such persons are required by SEC regulations to furnish us with copies of all Section 16(a) forms that they file.

To our knowledge, based solely on our review of the copies of such reports received by us and written representations that no other reports were required for those persons during 2014, all filing requirements were met except, due to administrative constraint, as provided in this paragraph. Bryan E. Seas made a single late filing reporting a single transaction. Andrew W. Evans, Henry P. Linginfelter, Melanie M. Platt, Paul R. Shlanta and Peter I. Tumminello each made a single late filing reporting two transactions. John W. Somerhalder II made two late filings reporting two transactions in the first late filing and a single transaction in the second late filing.

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GENERAL INFORMATION

2014 Annual Report

A copy of our 2014 annual report is available on the internet at *www.proxyvote.com* and at our website at www.aglresources.com. The annual report, which contains financial and other information about us, is not incorporated in this proxy statement and is not a part of the proxy soliciting material.

Availability of Corporate Governance Documents

Our Standards for Determining Director Independence, our Corporate Governance Guidelines, our Code of Business Conduct, our Code of Ethics, and the charters of each of our board committees are available on our website at *www.aglresources.com* and are available in print to any shareholder who requests them. You may contact our Corporate Secretary for copies at:

AGL Resources Inc.
Attn: Corporate Secretary
P.O. Box 4569, Location 1466
Atlanta, Georgia 30302-4569

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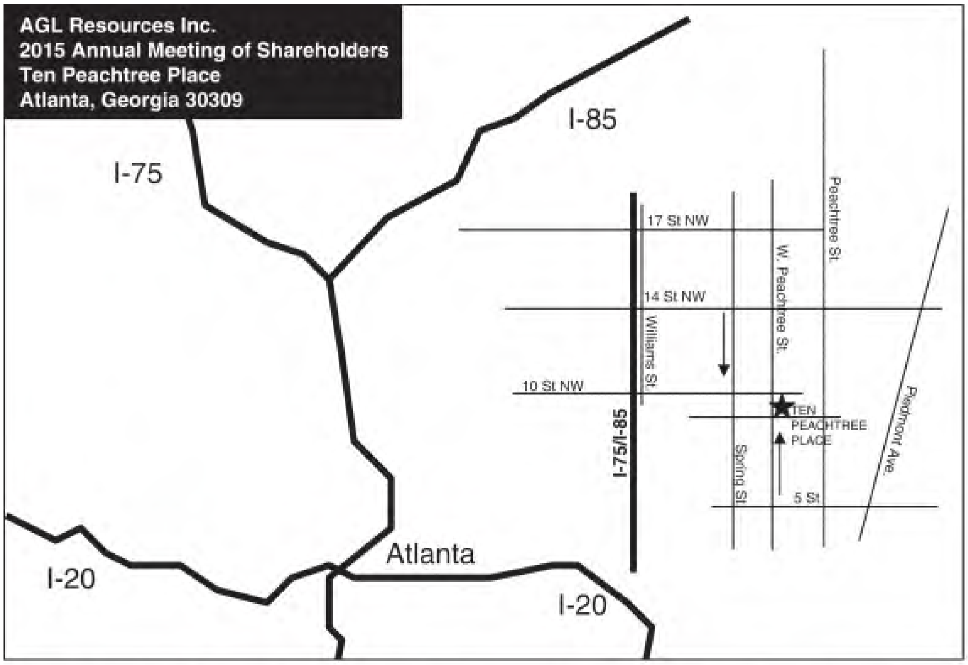

From Downtown Atlanta –Traveling north on I-75/I-85 take exit 250,10th-14th Street/ Georgia Tech. At the first traffic light, turn right onto 10th Street and almost immediately turn right onto Spring Street (one way), staying in the far left lane. Turn left onto Peachtree Place (at Publix), proceed across W. Peachtree Street and parking will be on your right.

From North Atlanta –Traveling south on I-75, take exit 250, 16th Street/14th Street/10th Street. At the second traffic light, turn left onto 10th Street, driving over the Interstate. At the second traffic light, turn right onto Spring Street (one way), staying in the far left lane. Turn left onto Peachtree Place (at Publix), proceed across W. Peachtree Street and parking will be on your right.

Traveling south on I-85, take exit 84, 17th Street/14th Street/10th Street. Take the left fork and stay on the access road to 10th Street. At the traffic light at 10th Street, turn left onto 10th Street, driving over the Interstate. At the second traffic light, turn right onto Spring Street (one way), staying in the far left lane. Turn left onto Peachtree Place (at Publix), proceed across W. Peachtree Street and parking will be on your right.

Public transportation is conveniently available via the Midtown MARTA station, located immediately adjacent to Ten Peachtree Place.

AGL Resources®

Ten Peachtree Place, N.E., Atlanta, Georgia 30309, aglresources.com

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AGL Resources

AGL RESOURCES INC.
MYRA C. BIERRIA
10 PEACHTREE PLACE, LOCATION 1466
ATLANTA, GA 30309

Your telephone or Internet vote authorizes the proxies to vote these shares in the same manner as if you marked, signed and returned your proxy card.

VOTE BY INTERNET - www.proxyvote.com
Use the Internet to transmit your voting instructions and for electronic delivery of information up until 11:59 p.m. Eastern Time on April 27, 2015 (or 11:59 p.m. Eastern Time on April 24, 2015 for shares allocated to your account under one of the Company's 401(k) plans). Have your proxy card in hand when you access the web site and follow the instructions to obtain your records and to create an electronic voting instruction form.

ELECTRONIC DELIVERY OF FUTURE PROXY MATERIALS
If you would like to reduce the costs incurred by our company in mailing proxy materials, you can consent to receiving all future proxy statements, proxy cards and annual reports electronically via e-mail or the Internet. To sign up for electronic delivery, please follow the instructions above to vote using the Internet and, when prompted, indicate that you agree to receive or access proxy materials electronically in future years.

VOTE BY PHONE - 1-800-690-6903
Use any touch-tone telephone to transmit your voting instructions up until 11:59 p.m. Eastern Time on April 27, 2015 (or 11:59 p.m. Eastern Time on April 24, 2015 for shares allocated to your account under one of the Company's 401(k) plans). Have your proxy card in hand when you call and then follow the instructions.

VOTE BY MAIL
Mark, sign and date your proxy card and return it in the postage-paid envelope we have provided or return it to Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717.

TO VOTE, MARK BLOCKS BELOW IN BLUE OR BLACK INK AS FOLLOWS:

M83548-P60668 KEEP THIS PORTION FOR YOUR RECORDS

THIS PROXY CARD IS VALID ONLY WHEN SIGNED AND DATED. DETACH AND RETURN THIS PORTION ONLY

AGL RESOURCES INC.

The Board of Directors recommends that you vote FOR all nominees listed under Item 1 and FOR Items 2, 3 and 4.

Vote on Directors

1. Election of Directors

Nominees:	**For**	**Against**	**Abstain**
1a. Sandra N. Bane	☐	☐	☐
1b. Thomas D. Bell, Jr.	☐	☐	☐
1c. Norman R. Bobins	☐	☐	☐
1d. Charles R. Crisp	☐	☐	☐
1e. Brenda J. Gaines	☐	☐	☐
1f. Arthur E. Johnson	☐	☐	☐
1g. Wyck A. Knox, Jr.	☐	☐	☐
1h. Dennis M. Love	☐	☐	☐
1i. Dean R. O'Hare	☐	☐	☐
1j. Armando J. Olivera	☐	☐	☐
1k. John E. Rau	☐	☐	☐

	For	**Against**	**Abstain**
1l. James A. Rubright	☐	☐	☐
1m. John W. Somerhalder II	☐	☐	☐
1n. Bettina M. Whyte	☐	☐	☐
1o. Henry C. Wolf	☐	☐	☐

Vote on Proposals

2. The ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2015.	☐	☐	☐
3. The approval of a non-binding resolution to approve the compensation of our named executive officers.	☐	☐	☐
4. The approval of an amendment to the Company's amended and restated articles of incorporation to provide holders of at least 25% of the voting power of all outstanding shares entitled to vote the right to call a special meeting of shareholders.	☐	☐	☐

The Board of Directors recommends you vote AGAINST Items 5 and 6.

5. Shareholder proposal regarding independent chairman policy.	☐	☐	☐

6. Shareholder proposal regarding goals for reducing greenhouse gas emissions. ☐ ☐ ☐

For address changes and/or comments, please check this box and write them on the back where indicated. ☐

Please indicate if you plan to attend this meeting. ☐ ☐

Yes **No**

NOTE: Such other business as may properly come before the meeting or any adjournment thereof.

THIS PROXY, WHEN PROPERLY EXECUTED, WILL BE VOTED AS DIRECTED OR, IF NO DIRECTION IS GIVEN, WILL BE VOTED FOR ALL NOMINEES LISTED UNDER ITEM 1, FOR PROPOSALS 2, 3 AND 4 AND AGAINST PROPOSALS 5 AND 6.

Please sign name(s) exactly as shown below. When signing as executor, administrator, trustee or guardian, give full title as such; when shares have been issued in names of two or more persons, all should sign.

Signature [PLEASE SIGN WITHIN BOX]	Date	Signature (Joint Owners)	Date

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Please present this admission ticket and valid picture identification
for admission to the Annual Meeting

Important Notice Regarding the Availability of Proxy Materials for the Annual Meeting:
The Notice and Proxy Statement, and Annual Report/10-K Wrap are available at www.proxyvote.com.

Please detach here

M83549-P60668

AGL Resources Inc.
ANNUAL MEETING OF SHAREHOLDERS
Tuesday, April 28, 2015
10:00 a.m., Eastern Time
10 Peachtree Place
Atlanta, Georgia 30309

AGL Resources

Revocable Proxy - Common Stock

THIS PROXY IS SOLICITED BY THE BOARD OF DIRECTORS FOR THE 2015 ANNUAL MEETING OF SHAREHOLDERS

The undersigned hereby appoints John W. Somerhalder II, Paul R. Shlanta and Andrew W. Evans, and each of them, proxies, with full power of substitution, to act for and in the name of the undersigned, to vote all shares of Common Stock of AGL Resources Inc. (the "Company") that the undersigned is entitled to vote at the 2015 Annual Meeting of Shareholders of the Company, to be held on Tuesday, April 28, 2015, and at any and all adjournments or postponements thereof, as indicated on the reverse side of this card.

The undersigned hereby appoints Merrill Lynch Bank & Trust Co., FSB, which acts as Trustee for the AGL Resources Inc. Retirement Savings Plus Plan (the "AGL 401(k) Plan") and the Nicor Gas Thrift Plan (the "Nicor 401(k) Plan"), as proxy, to act for and in the name of the undersigned, to vote all shares of Common Stock of the Company that have been allocated to the account of the undersigned under the AGL 401(k) Plan or the Nicor 401(k) Plan, as applicable, at the 2015 Annual Meeting of Shareholders of the Company, to held on Tuesday, April 28, 2015, and at any and all adjournments or postponements thereof, as indicated on the reverse side of this card. Under the terms of the AGL 401(k) Plan and the Nicor 401(k) Plan, only the Trustee of the plan can vote the shares allocated to the accounts of the participants, even if such participants or their beneficiaries attend the Annual Meeting in person.

Receipt of the Notice of the Annual Meeting, the accompanying Proxy Statement and the 2014 Annual Report to Shareholders is hereby acknowledged.

PLEASE VOTE, DATE AND SIGN ON REVERSE AND RETURN PROMPTLY IN THE ENCLOSED POSTAGE-PAID ENVELOPE.

Your telephone or Internet vote authorizes the proxies to vote the shares in the same manner as if you marked, signed and returned your proxy card.

Address Changes/Comments: ____________________

____

(If you noted any Address Changes/Comments above, please mark corresponding box on the reverse side.)

See reverse for voting instructions.

Exhibit 5

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014

Commission File Number 1-14174

AGL RESOURCES INC.

Ten Peachtree Place NE,
Atlanta, Georgia 30309

404-584-4000

Georgia	**58-2210952**
(State of incorporation)	(I.R.S. Employer Identification No.)

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

Title of each class	Name of each exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**

AGL Resources Inc. is a well-known seasoned issuer.

AGL Resources Inc. is required to file reports pursuant to Section 13 of the Securities Exchange Act.

AGL Resources Inc.: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

AGL Resources Inc. has submitted electronically and posted on its corporate website every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months.

AGL Resources Inc. believes that during the 2014 fiscal year, its executive officers, directors and 10% beneficial owners subject to Section 16(a) of the Securities Exchange Act complied with all applicable filing requirements, except as set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in AGL Resources Inc.’s Proxy Statement for the 2015 Annual Meeting of Shareholders.

AGL Resources Inc. is a large accelerated filer and is not a shell company.

The aggregate market value of AGL Resources Inc.’s common stock held by non-affiliates of the registrant (based on the closing sale price on June 30, 2014, as reported by the New York Stock Exchange), was $6,574,107,387.

The number of shares of AGL Resources Inc.’s common stock outstanding as of February 4, 2015 was 119,656,937

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2015 Annual Meeting of Shareholders (Proxy Statement) to be held on April 28, 2015, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF KEY TERMS

AFUDC	Allowance for funds used during construction, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support the AGL Capital commercial paper program
AGL Resources	AGL Resources Inc., together with its consolidated subsidiaries
Atlanta Gas Light	Atlanta Gas Light Company
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Chicago Hub	A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies
Compass Energy	Compass Energy Services, Inc., which was sold in 2013
Dalton Pipeline	A 50% undivided ownership interest in a pipeline facility in Georgia
EBIT	Earnings before interest and taxes, the primary measure of our reportable segments' profit or loss, which includes operating income and other income and excludes financing costs, including interest on debt and income tax expense
EPA	U.S. Environmental Protection Agency
ERC	Environmental remediation costs associated with our distribution operations segment that are generally recoverable through rate mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission, the state regulatory agency for Atlanta Gas Light
Georgia Natural Gas	The trade name under which SouthStar does business in Georgia
Golden Triangle	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Horizon Pipeline	Horizon Pipeline Company, LLC
HVAC	Heating, ventilation and air conditioning
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LDC	Local Distribution Company
LIBOR	London Inter-Bank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
MGP	Manufactured gas plant
Moody's	Moody's Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold and revenue tax expense
OTC	Over-the-counter
Pad gas	Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility, also known as base gas
PBR	Performance-based rate, a regulatory plan at Nicor Gas that provided economic incentives based on natural gas cost performance. The plan terminated in 2003
PennEast Pipeline	PennEast Pipeline Company, LLC
PGA	Purchased Gas Adjustment
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, doing business as Pivotal Home Solutions
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SouthStar	SouthStar Energy Services LLC
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Triton	Triton Container Investments LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited
U.S.	United States
VaR	Value-at-risk is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability.
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
WACC	Weighted average cost of capital
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

PART I

ITEM 1. BUSINESS

Unless the context requires otherwise, references to "we," "us," "our" and the "company" are intended to mean AGL Resources Inc. The operations and businesses described in this filing are owned and operated, and management services are provided, by distinct direct and indirect subsidiaries of AGL Resources. AGL Resources was organized and incorporated in 1995 under the laws of the State of Georgia.

Business Overview

AGL Resources, headquartered in Atlanta, Georgia, is an energy services holding company whose primary business is the distribution of natural gas through our natural gas distribution utilities. We also are involved in several other businesses that are mainly related and complementary to our primary business. Our segments consist of the following four reportable segments, which are consistent with how management views and manages our businesses.

Distribution Operations
- Operation, construction and maintenance of 80,700 miles of natural gas pipeline and 14 storage facilities to provide safe and cost-effective service of natural gas to residential, commercial and industrial customers
- Serves 4.5 million customers across 7 states
- Rates of return are regulated by each individual state in return for exclusive franchises

Retail Operations
- Provision of natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice
- Serves 628,000 energy customers and 1.2 million service contracts across 15 states

Wholesale Services
- Engages in natural gas storage, gas pipeline arbitrage and provides natural gas asset management and/or related logistics services for most of our utilities, as well as for non-affiliated companies
- Serves a variety of customers in the natural gas value chain with operations structured to optimize storage and transportation portfolios under a wide range of market conditions through the use of hedging tools that allow us to capture additional value while limiting risk

Midstream Operations
- Consists primarily of high deliverability natural gas storage facilities and select pipelines, enabling the provision of diverse sources of natural gas supplies to our customers

For more information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and Note 13 to our consolidated financial statements under Item 8 herein.

Distribution Operations

Our distribution operations segment is the largest component of our business and includes seven natural gas local distribution utilities with their primary focus being the safe and reliable delivery of natural gas. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

Utility	State	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas	Illinois	2,195	34,100
Atlanta Gas Light	Georgia	1,560	32,600
Virginia Natural Gas	Virginia	287	5,500
Elizabethtown Gas	New Jersey	281	3,200
Florida City Gas	Florida	105	3,600
Chattanooga Gas	Tennessee	63	1,600
Elkton Gas	Maryland	6	100
Total		4,497	80,700

Competition and Customer Demand

Our utilities do not compete with other distributors of natural gas in their exclusive franchise territories, but face competition from other energy products. Our principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial and industrial markets throughout our service areas for our customers who are considering switching from a natural gas appliance. Accordingly, the potential displacement or replacement of natural gas appliances with electric appliances is a competitive factor.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- change in the availability or price of natural gas and other forms of energy;

- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations; and
- the cost and capability to convert from natural gas to alternative energy products;

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

The natural gas related programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, we partner with numerous third-party entities such as builders, realtors, plumbers, mechanical contractors, architects and engineers to market the benefits of natural gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Recent advances in natural gas drilling in shale producing regions in the U.S. have resulted in historically high supplies of natural gas and historically low prices for natural gas. This dynamic has provided solid cost advantages for natural gas when compared to electricity, fuel oil and propane and opportunities for growth for our businesses.

Sources of Natural Gas Supply and Transportation Services

Procurement plans for natural gas supply and transportation to serve our regulated utility customers are reviewed and approved by our state utility commissions. We purchase natural gas supplies in the open market by contracting with producers, marketers and from our wholly owned subsidiary, Sequent, under asset management agreements in states where this is approved by the state commission. We also contract for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, we may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of our utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities and other supply sources, arranged by either our transportation customers or us. We have consistently been able to obtain sufficient supplies of natural gas to meet customer requirements. We believe natural gas supply and pipeline capacity will be sufficiently available to meet market demands in the foreseeable future.

Utility Regulation and Rate Design

Rate Structures Our utilities operate subject to regulations and oversight of the state regulatory agencies in each of the states served by our utilities with respect to rates charged to our customers, maintenance of accounting records and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. These agencies approve rates designed to provide us the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of the utility plant in service, working capital and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers;
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks;
- reading meters and maintaining underlying customer premise information for Marketers; and
- planning and contracting for capacity on interstate transportation and storage systems.

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia Commission and periodically adjusted. The Marketers add these fixed charges when billing customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light’s revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of our regulated utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. We have various mechanisms, such as weather normalization mechanisms and weather derivative instruments, in place at most of our utilities that limit our exposure to weather changes within typical ranges in these utilities’ respective service areas.

All of our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need nor utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost of this gas through recovery mechanisms approved by the Georgia Commission specific to Georgia's deregulated market. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to environmental remediation and energy efficiency plans. In traditional rate designs, utilities recover a significant portion of their fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by our customers. Three of our utilities have decoupled regulatory mechanisms in place that encourage conservation. We believe that separating, or decoupling, the recoverable amount of these fixed costs from the customer throughput volumes, or amounts of natural gas used by our customers, allows us to encourage our customers' energy conservation and ensures a more stable recovery of our fixed costs. The following table provides regulatory information for our six largest utilities.

$ in millions	**Nicor Gas** (9)	**Atlanta Gas Light**	**Virginia Natural Gas**	**Elizabethtown Gas**	**Florida City Gas**	**Chattanooga Gas**
Authorized return on rate base (1)	8.09%	8.10%	7.38%	7.64%	7.36%	7.41%
Estimated 2014 return on rate base (2)	8.56%	7.80%	6.45%	8.22%	5.37%	7.94%
Authorized return on equity (1)	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2014 return on equity (2)	12.12%	10.16%	8.77%	11.52%	8.41%	11.19%
Authorized rate base % of equity (1)	51.07%	51.00%	45.36%	47.89%	36.77%	46.06%
Rate base included in 2014 return on equity (2)	$1,561	$2,315	$590	$519	$182	$104
Weather normalization (3)			✓	✓		✓
Decoupled or straight-fixed-variable rates (4)		✓	✓			✓
Regulatory infrastructure program rates (5)	✓	✓	✓	✓		
Bad debt rider (6)	✓		✓			✓
Synergy sharing policy (7)		✓				
Energy efficiency plan (8)	✓		✓	✓	✓	✓
Last decision on change in rates	2009	2010	2011	2009	N/A	2010

(1) The authorized return on rate base, return on equity and percentage of equity were those authorized as of December 31, 2014.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction. Rate base includes investments in regulatory infrastructure programs.
(3) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer-than-normal and decreasing amounts charged when weather is colder-than-normal.
(4) Decoupled and straight-fixed-variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers.
(5) Includes programs that update or expand our distribution systems and liquefied natural gas facilities.
(6) Involves the recovery (refund) of the amount of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through purchased gas adjustment (PGA) mechanisms.
(7) Involves the recovery of 50% of net synergy savings achieved on mergers and acquisitions.
(8) Includes the recovery of costs associated with plans to achieve specified energy savings goals.
(9) In connection with the December 2011 Nicor merger, we agreed to (i) not initiate a rate proceeding for Nicor Gas that would increase base rates prior to December 2014, (ii) maintain 2,070 full-time equivalent employees involved in the operation of Nicor Gas for a period of three years and (iii) maintain the personnel numbers in specific areas of safety oversight of the Nicor Gas system for a period of five years.

Current Regulatory Proceedings

Nicor Gas In June 2013, in connection with the PBR plan, the Illinois Commission issued an order requiring us to refund $72 million to current Nicor Gas customers through our PGA mechanism based upon natural gas throughput over 12 months beginning in July 2013. Approximately $43 million was refunded during 2014 and $29 million was refunded during 2013. For more information on the PBR plan, see Note 11 to our consolidated financial statements under Item 8 herein.

In August 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services, requesting refunds of $18 million and $22 million, respectively. We filed surrebuttal testimony in December 2014 disputing that any refund is due, as Nicor Gas was authorized to enter into these transactions and revenues associated with such reduced rate payer costs as either credits to the PGA or reductions to base rates were consistent with then-current Illinois Commission orders governing these activities. We believe these claims engage in hindsight speculation, which is expressly prohibited in a prudence review examination, and we intend to vigorously defend against these claims. Evidentiary hearings are scheduled for March 2015. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Nicor Gas' first three-year energy efficiency program, which outlines energy efficiency program offerings and therm reduction goals for a three-year period, ended in May 2014. Nicor Gas spent $125 million on the program and reduced customer usage by an estimated 46 million therms. Additionally, in May 2014, the Illinois Commission approved Nicor

Gas' second energy efficiency program, Energy Smart Plan, with expected spending of $93 million over a three-year period that began in June 2014. Nicor Gas spent $14 million on this new program in 2014.

Atlanta Gas Light In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. In September 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several Marketers that included a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. The Georgia Commission approved the stipulation in December 2014. Over the five-year period, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, will be used to resolve 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light is obligated to resolve 25% and we have recorded a reserve in our Consolidated Statements of Financial Position representing the future estimated cost to purchase the approximately 1.15 Bcf of natural gas. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all certificated Marketers through charges for system retained storage gas as it is used by the certificated Marketers.

In accordance with an order issued by the Georgia Commission, where AGL Resources makes a business acquisition that reduces the costs allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a ten-year period. In December 2013, we filed a Report of Synergy Savings with the Georgia Commission in connection with the Nicor acquisition. If and when approved, the net savings should result in annual rate reductions to the firm customers of Atlanta Gas Light of $5 million. We expect this filing to be discussed by the staff of the Georgia Commission in February 2015.

We expect Atlanta Gas Light to file a petition with the Georgia Commission for approval of a rate increase to our STRIDE surcharge associated with the final accounting of our pipeline replacement program (PRP) in February 2015. The proposed rate increase is designed to collect the unrecovered revenue requirement of the program and is in accordance with the requirements set forth by the Georgia Commission that allows Atlanta Gas Light to make a true-up filing at the end of the program to recover the actual costs of the program. The program ended December 31, 2013.

Virginia Natural Gas In April 2014, the Governor of Virginia signed into law legislation that enables the state's natural gas utilities, including Virginia Natural Gas, to acquire long-term supplies of natural gas and make capital investments to facilitate the delivery of low-cost shale and coal-bed methane gas to Virginia homeowners and businesses. Under the terms of the new statute, Virginia Natural Gas could enter into commercial agreements to obtain up to 25% of its annual firm sales demand for natural gas through long-term contracts or investments such as purchases of reserves. Recovery on investments would be based upon the utility's authorized return on rate base, which would flow through the PGA mechanism or a similar mechanism. The new statute also allows us to build pipelines and other infrastructure that deliver shale and coal-bed methane gas into the state's markets that seek to reduce natural gas supply costs or reduce price volatility for consumers. All filings under this legislation require approval by the Virginia Commission, and we have not made any filings to date.

Supply Six of our utilities use asset management agreements with our wholly owned subsidiary, Sequent, for the primary purpose of reducing our utility customers' gas cost recovery rates through payments to the utilities by Sequent. For Atlanta Gas Light, these payments are controlled by the Georgia Commission and utilized for infrastructure improvements and to fund heating assistance programs, rather than for a reduction to gas cost recovery rates. Under these asset management agreements, Sequent supplies natural gas to the utility and markets available pipeline and storage capacity to improve the overall cost of supplying gas to the utility customers. Currently, the utilities primarily purchase their gas from Sequent. The purchase agreements require Sequent to provide firm gas to our utilities. However, these utilities maintain the right and ability to make their own gas supply purchases. This right allows our utilities to make long-term supply arrangements if they believe it is in the best interest of their customers. Nicor Gas has not entered into an asset management agreement with Sequent or any other parties.

Each agreement with Sequent has either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without any annual minimum guarantee, or a fixed fee. From the inception of these agreements in 2001 through 2014, Sequent has made sharing payments under these agreements totaling $272 million. The following table provides payments made by Sequent to our utilities under these agreements during the last three years.

	Total amount received			
In millions	**2014**	**2013**	**2012**	**Expiration Date**
Elizabethtown Gas	$18	$6	$5	March 2019
Virginia Natural Gas	14	4	3	March 2016
Atlanta Gas Light	13	6	5	March 2017
Florida City Gas	1	1	1	(1)
Chattanooga Gas	1	1	1	March 2018
Total	$47	$18	$15	

(1) The term of the agreement is evergreen and renews automatically each year unless terminated by either party.

Transportation Our utilities use firm pipeline entitlements, storage services and/or peaking capacity contracted with interstate capacity providers to serve the firm natural gas supply needs of our customers. In addition, Nicor Gas, Atlanta

Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas operate on-system LNG facilities, underground natural gas storage fields and/or propane/air plants to meet the gas supply and deliverability requirements of their customers in the winter period. Generally, we work to build a portfolio of year-round firm transportation, seasonal storage and short-duration peaking services that will meet the needs of our customers under severe weather conditions with adequate operational flexibility to reliably manage the variability inherent in servicing customers using natural gas for space heating. Including seasonal storage and peaking services in this portfolio is more efficient and cost effective than reserving firm pipeline capacity rights all year for a limited number of cold winter days.

Our firm contracts range in duration from 3 to 25 years. We work to stagger terms to maintain our ability to adjust the overall portfolio to meet changing market conditions. Our utilities have contracted for capacity that is predominately sourced from producing areas in the midcontinent and gulf coast regions, and they continue to evaluate capacity options that will provide long-term access to reliable and affordable natural gas supplies. During 2014, we announced our participation in three pipeline projects that will provide access to shale gas in the proximity of our service territories. We have entered into longer-term contracts in connection with these pipeline projects, which resulted in an increase in the duration of our firm contracts compared to prior years. Given the number of agreements held by our utilities and the amount of capacity under contract, we make decisions as to the termination, extension or renegotiation of contracts every year.

Capital Projects

We continue to focus on capital discipline and cost control while moving ahead with projects and initiatives that we expect will have current and future benefits to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. Total capital expenditures incurred during 2014 for our distribution operations segment were $715 million. The following table and discussions provide updates on some of our larger capital projects under various programs at our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2015 are discussed in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Liquidity and Capital Resources.”

	Program	**Program details**	**Recovery**	**Expenditures in 2014** (in millions)	**Expenditures since project inception** (in millions)	**Miles of pipe installed since project inception**	**Scope of program** (total miles)	**Program duration** (years)	**Last year of program**
Atlanta Gas Light	Integrated Vintage Plastic Replacement Program (i-VPR)	(1)	Rider	$62	$67	194	756	4	2017
Atlanta Gas Light	Integrated System Reinforcement Program (i-SRP)	(2)	Rider	13	264	n/a	n/a	8	2017
Atlanta Gas Light	Integrated Customer Growth Program (i-CGP)	(3)	Rider	7	47	n/a	n/a	8	2017
Chattanooga Gas	Bare Steel & Cast Iron	(4)	Rate Based	17	32	71	111	10	2020
Elizabethtown Gas	Aging Infrastructure Replacement (AIR)	(4)	Rider / Rate Based	32	38	40	130	4	2017
Elizabethtown Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort (ENDURE)	(5)	Rate Based	2	2	4	13	1	2015
Florida City Gas	Galvanized Replacement Program	(6)	Rate Based	1	14	75	111	17	2017
Nicor Gas	Investing in Illinois (Qualified Infrastructure)	(7) (8)	Rider	22	22	13	800	9	2023
Virginia Natural Gas	Steps to Advance Virginia’s Energy (SAVE)	(7)	Rider	24	64	127	250	5	2017
	Total			$180	$550	524	2,171		

(1) Early vintage plastic, risk based mid vintage plastic, mid vintage neighborhood convenience.
(2) Large diameter pressure improvement and system reinforcement projects.
(3) New business construction and strategic line extension.
(4) Cast iron and bare steel.
(5) Cast iron and distribution reinforcement.
(6) Galvanized and X-Tube steel. Expenditures and miles reported are post AGL Resources acquisition.
(7) Cast iron, bare steel, mid vintage plastic and risk based materials.
(8) Represents expenditures on qualifying infrastructure that will be placed into service after the rate freeze date, December 9, 2014.

Atlanta Gas Light Our STRIDE program is comprised of i-SRP, i-CGP and i-VPR. STRIDE includes a surcharge on firm customers that provides recovery of the revenue requirement for the ongoing programs and the PRP, which ended on December 31, 2013. These infrastructure development, enhancement and replacement programs are used to update and expand distribution systems and liquefied natural gas facilities, improve system reliability and meet operational flexibility and growth. The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Under I-SRP, we must file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

A new $260 million, four-year STRIDE program was approved in December 2013, of which $214 million is for i-SRP related projects and $46 million is for i-CGP related projects. The program will be funded through a monthly rider surcharge per customer of $0.48 beginning in January 2015, which will increase to $0.96 beginning in January 2016 and to $1.43 beginning in January 2017. This surcharge will continue through 2025.

The purpose of the i-VPR program is to replace aging plastic pipe that was installed primarily in the mid-1960's to the early 1980's. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for replacement over the next 15 - 20 years as it reaches the end of its useful life. In 2013, the Georgia Commission approved i-VPR, which includes the replacement of the first 756 miles of vintage plastic pipe over four years for $275 million. The program is being funded through an increase in the STRIDE monthly rider surcharge per customer of $0.48 through December 2014, which increases to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016. This surcharge will continue through 2025. If the Georgia Commission elects to extend the i-VPR program beyond 2017, the remaining vintage plastic mains in our system could be considered for replacement through the program over the next 15 - 20 years as it reaches the end of its useful life. In December 2014, the Georgia Commission approved a stipulation between Atlanta Gas Light and the staff of the Georgia Commission that allows for the recovery or refund of certain operation and maintenance expenses associated with the i-VPR program that are above or below an established baseline amount of $7 million.

Nicor Gas In July 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average 4.0% of base rate revenues. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we may implement rates under the program effective in March 2015. Our filing included a project scope with cost estimates for three years of $171 million in 2015, $173 million in 2016 and $171 million in 2017. Our current project scope includes cost estimates that are approximately $200 million in 2015 and $250 million in each of 2016 and 2017. These expenditure levels represent approximately 1.3%, 3.5% and 4.0% of annual average base rate revenues for 2015, 2016 and 2017, respectively, which are all within the program requirements.

Elizabethtown Gas Our extension of the enhanced infrastructure program in 2013 allowed for infrastructure investment of $115 million over four years, effective as of September 2013, and is focused on the replacement of aging cast iron of our pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital (WACC) of 6.65%. We agreed to file a general rate case by September 2016. Prior accelerated infrastructure investments under this program will be recovered through a permanent adjustment to base rates.

In July 2014, the New Jersey BPU approved ENDURE, a program that will improve our distribution system's resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas will invest $15 million in infrastructure and related facilities and communication planning over a one year period from August 2014 through September 2015. The plan allows Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program.

Virginia Natural Gas The SAVE program, which was approved in August 2012, involves replacing aging infrastructure as prioritized through Virginia Natural Gas' distribution integrity management program. SAVE was filed in accordance with a Virginia statute providing a regulatory cost recovery mechanism for costs associated with certain infrastructure replacement programs. This five-year program includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering costs based on this program through a rate rider that became effective in August 2012. The second year performance rate update was approved by the Virginia Commission in July 2014 and became effective as of August 2014.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites. As we continue to conduct the MGP remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. These costs are primarily recovered through rate riders.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Critical Accounting Policies and Estimates" and Note 3 to our consolidated financial statements under Item 8 herein for additional information about our environmental remediation liabilities and efforts.

Retail Operations

Our retail operations segment serves approximately 628,000 natural gas commodity customers and 1.2 million service contracts. Companies within our retail operations segment include SouthStar and Pivotal Home Solutions.

SouthStar is one of the largest retail natural gas marketers in the United States and markets natural gas to residential, commercial and industrial customers, primarily in Georgia and Illinois, where we capture spreads between wholesale and retail natural gas prices. Additionally, we offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. We charge a fee or premium for these services. Through our commercial operations, we optimize storage and transportation assets and effectively manage commodity risk, which enables us to maintain competitive retail prices and operating margin.

SouthStar is a joint venture owned 85% by us and 15% by Piedmont and is governed by an executive committee with equal representation by both owners. After considering the relevant factors, we consolidate SouthStar in our financial statements. See Note 10 to our consolidated financial statements under Item 8 herein for more information.

Pivotal Home Solutions provides a suite of home protection products and services that offer homeowners additional financial stability regarding their energy service delivery, systems and appliances. We offer a proprietary line of customizable home warranty and energy efficiency plans that can be co-branded with utility and energy companies. We have a portable product suite, which can be offered in most geographies and markets. Pivotal Home Solutions serves customers in several states, primarily Illinois, Indiana and Ohio. Additionally, we are working to expand product offerings to customers in our affiliate companies to enhance the customer experience and retention, as well as promote switching to natural gas from other energy products, such as electricity, propane or fuel oil.

Competition and Operations Our retail operations business competes with other energy marketers to provide natural gas and related services to customers in the areas in which they operate. In the Georgia market, SouthStar operates as Georgia Natural Gas and is the largest of 12 Marketers in the state, with average customers of nearly 500,000 over the last three years and market share of approximately 31% during 2014.

In recent years, increased competition and the heavy promotion of fixed-price plans by SouthStar's competitors have resulted in increased pressure on retail natural gas margins. In response to these market conditions, SouthStar's residential and commercial customers have been migrating to fixed-price plans, which, combined with increased competition from other Marketers, has impacted SouthStar's customer growth as well as margins. However, SouthStar has utilized new products and marketing partnerships to stabilize its portfolio mix in Georgia and has entered new retail markets to position the company for future growth.

In addition, similar to our natural gas utilities, our retail operations businesses face competition based on customer preferences for natural gas compared to other energy products, primarily electricity, and the comparative prices of those products. We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers.

SouthStar's operations are sensitive to seasonal weather, natural gas prices, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar's retail pricing strategies and the use of a variety of hedging strategies, such as the use of futures, options, swaps, weather derivative instruments and other risk management tools, help to ensure retail customer costs are covered to mitigate the potential effect of these issues and commodity price risk on its operations. For more information on SouthStar's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Natural Gas Price Risk."

Our retail operations business also experiences price, convenience and service competition from other warranty and HVAC companies. These businesses also bear risk from potential changes in the regulatory environment.

Wholesale Services

Our wholesale services segment consists of our wholly owned subsidiary, Sequent, which engages in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the U.S. and Canada. Wholesale services utilizes a portfolio of natural gas storage assets, contracted supply from all of the major producing regions, as well as contracted storage and transportation capacity to provide these services to its customers. Its customers consist primarily of electric and natural gas utilities, power generators and large industrial customers. Our logistical expertise enables us to provide our customers with natural gas from the major producing regions and market hubs. We also leverage our portfolio of natural gas storage assets and contracted natural gas supply, transportation and storage capacity to meet our delivery requirements and customer obligations at competitive prices.

Wholesale services' portfolio of storage and transportation capacity enables us to generate additional operating margin by optimizing the contracted assets through the application of our wholesale market knowledge and risk management skills as opportunities arise. These asset optimization opportunities focus on capturing the value from idle or underutilized assets, typically by participating in transactions that take advantage of volatility in pricing differences between varying geographic locations and time horizons (location and seasonal spreads) within the natural gas supply, storage and transportation markets to generate earnings. We seek to mitigate the commodity price and volatility risks and protect our operating margin through a variety of risk management and economic hedging activities.

In May 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers. Under the terms of the purchase and sale agreement, we received an initial cash payment of $12 million, resulting in a pre-tax gain of $11 million ($5 million net of tax) and were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received a cash payment of $4 million, resulting in the recognition of a $3 million gain. We have a five-year agreement through April 2018 to supply natural gas to our former customers.

Competition and operations Wholesale services competes for asset management, long-term supply and seasonal peaking service contracts with other energy wholesalers, often through a competitive bidding process. We are able to price competitively by utilizing our portfolio of contracted storage and transportation assets and by renewing and adding new contracts at prevailing market rates. We will continue to broaden our market presence where our portfolio of contracted storage and transportation assets provides us a competitive advantage, as well as continue our pursuit of additional opportunities with power generation companies and natural gas producers located in the areas of the country in which we operate. We are also focused on building our fee-based services as a source of operating margin that is less impacted by volatility in the marketplace.

We view our wholesale margins from two perspectives. First, we base our commercial decisions on economic value for both our natural gas storage and transportation transactions. For our natural gas storage transactions, economic value is determined based on the net operating revenue to be realized at the time the physical gas is withdrawn from storage and sold and the derivative instrument used to economically hedge natural gas price risk on the physical storage is settled. Similarly, for our natural gas transportation transactions, economic value is determined based on the net operating revenue to be realized at the time the physical gas is purchased, transported, and sold utilizing our transportation capacity along with the settlement value associated with any derivative instruments.

The second perspective is the values reported in accordance with GAAP and encompassing periods prior to and in the period of physical withdrawal and sale of inventory or purchase, transportation and sale of natural gas. We enter into derivatives to hedge price risk prior to when the related physical storage withdrawal or transportation transactions occur based upon our commercial evaluation of future market prices. The reported GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value and prior to the period the related physical storage and transportation transactions occur and are recognized in earnings. The change in fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. This results in reported earnings volatility during the interim periods; however, the expected margin based upon the hedged economic value is ultimately realized in the period natural gas is physically withdrawn from storage or transported and sold at market prices and the related hedging instruments are settled.

For our natural gas storage portfolio, we purchase natural gas for storage when the current market price we pay plus the cost for transportation, storage and financing is less than the market price we anticipate we could receive in the future. We attempt to mitigate substantially all of the commodity price risk associated with our storage portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or OTC derivatives in forward months to substantially protect the operating revenue that we will ultimately realize when the stored gas is actually sold.

Our natural gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge natural gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs.

Midstream Operations

Our midstream operations segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets in the Gulf Coast region of the U.S. and in northern California. While this business can generate additional revenue during times of peak market demand for natural gas storage services, our natural gas storage facilities have a portfolio of short, medium and long-term contracts at fixed market rates. In addition to natural gas storage, this segment also includes our developing LNG business, which focuses on LNG for transportation, and select pipeline investments that are outside of state regulatory jurisdiction.

Pipelines During 2014, we entered into three pipeline agreements, as indicated in the following table, which are subject to regulatory approvals. These projects, along with our existing pipelines discussed below, will support our efforts to provide diverse sources of natural gas supplies to our customers, resolve current and long-term supply planning for new capacity, enhance system reliability and generate economic development in the areas served. The pipeline development projects will be financed through a combination of commercial paper and long-term debt issuances. See Note 10 to the consolidated financial statements under Item 8 herein for additional information.

Dollars in millions	**Miles of pipe**	**Expected capital expenditures** (1)	**Ownership interest** (1)	**Scheduled year of completion**	**Expected FERC filing process** File date	Approval date
Dalton Pipeline (2)	106	$210	50%	2017	2015	2016
PennEast Pipeline (3)	108	200	20%	2017	2015	2016
Atlantic Coast Pipeline (4)	550	260	5%	2018	2015	2016
Total	764	$670				

(1) Represents our expected capital expenditures and ownership interest, which may change.
(2) In April 2014, we entered into two agreements associated with the construction of the Dalton Lateral Pipeline, which will serve as an extension of the Transco pipeline system and provide additional natural gas supply to our customers in Georgia. The first is a construction and ownership agreement and the second is an agreement to lease our ownership in this lateral pipeline extension once it is placed in service.
(3) In August 2014, we entered into a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to our customers in New Jersey. We believe this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during the past winter.
(4) In September 2014, we entered into a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to our customers in Virginia.

Magnolia Enterprise Holdings, Inc. This wholly owned subsidiary operates a pipeline that provides our Georgia customers diversification of natural gas sources and increased reliability of service in the event that supplies coming from other supply sources are disrupted.

Horizon Pipeline This 50% owned joint venture with Natural Gas Pipeline Company of America operates an approximate 70 mile natural gas pipeline stretching from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas has contracted for approximately 80% of Horizon Pipeline's total throughput capacity of 0.38 Bcf under an agreement expiring in May 2025.

Competition and operations Our natural gas storage facilities primarily compete with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Salt caverns have also been leached from bedded salt formations in the Northeastern and Midwestern states. Competition for our Central Valley storage facility primarily consists of storage facilities in northern California and western North America.

The market fundamentals of the natural gas storage business are cyclical. The abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. In 2014, expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to continue in 2015 as compared to historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy continues to improve, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. We believe our storage assets are strategically located to benefit from these expected improvements in market fundamentals, including the overall growth in the natural gas market, and there are significant barriers to developing new storage facilities, including construction time and other costs, federal, state and local permitting and approvals and suitable and available sites, to capitalize on these expected improvements in market conditions.

Other

Our "other" non-reportable segment includes aggregated subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our reportable segments. This segment includes our investment in Triton, which was not part of the sale of Tropical Shipping that closed on September 1, 2014. See Note 14 to the consolidated financial statements under Item 8 herein for additional information on the disposition of Tropical Shipping. AGL Services Company is a service company we established to provide certain centralized shared services to our reportable segments. We allocate substantially all of AGL Services Company's operating expenses and interest costs to our reportable segments in accordance with state regulations. Our EBIT results include the impact of these allocations to the various reportable segments.

AGL Capital, our wholly owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt instruments and other financing arrangements.

Employees

As of December 31, 2014, we had approximately 5,165 employees, all of whom were in the U.S. The decrease in total employees from 2013 primarily resulted from the sale of our Tropical Shipping business in 2014.

The following table provides information about our natural gas utilities' collective bargaining agreements, which represent approximately 33% of our total employees.

	Number of employees	Contract expiration date
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19) (1)	1,386	February 2017
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50) (2)	139	May 2015
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	171	November 2015
Total	1,696	

(1) Nicor Gas' collective bargaining agreement expired in February 2014, and a new agreement was ratified in April 2014. The new agreement provides for additional operational enhancements and changes to certain benefits, but does not have a material effect on our consolidated financial statements.

(2) Contract negotiations are ongoing; however, we do not expect a new contract to be finalized prior to the expiration of the current contract. We have a continuation agreement in place and do not expect this to result in a work stoppage.

We believe that we have a good working relationship with our unionized employees and there have been no work stoppages at Virginia Natural Gas, Elizabethtown Gas, or Nicor Gas since we acquired those operations in 2000, 2004, and 2011, respectively. As we have done historically, we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the company and our employees. Our current collective bargaining agreements do not require our participation in multiemployer retirement plans and we have no obligation to contribute to any such plans.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and proxy statements, and amendments to those reports that we file with, or furnish to, the SEC are available free of charge at the SEC website http://www.sec.gov and at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with, or furnish such reports to, the SEC. However, our website and any contents thereof should not be considered to be incorporated by reference into this document. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations
P.O. Box 4569
Atlanta, GA 30302-4569
404-584-4000

In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for our 2015 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 17, 2015, and we will make it available on our website as soon as reasonably practicable thereafter. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each committee of our Board of Directors are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

ITEM 1A. RISK FACTORS

Forward-Looking Statements

This report and the documents incorporated by reference herein contain "forward-looking statements." These statements, which may relate to such matters as future earnings, growth, liquidity, supply and demand, costs, subsidiary performance, credit ratings, dividend payments, new technologies and strategic initiatives, often include words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "proposed," "seek," "should," "target," "would" or similar expressions. You are cautioned not to place undue reliance on forward-looking statements. While we believe that our expectations are reasonable in view of the information that we currently have, these expectations are subject to future events, risks and uncertainties, and there are numerous factors—many beyond our control—that could cause actual results to vary materially from these expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation, including any changes related to climate matters; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, and unexpected changes in project costs, including the cost of funds to finance these projects and our ability to recover our project costs from our customers; limits on pipeline capacity; the impact of acquisitions and divestitures, including recent acquisitions in our retail operations segment; our ability to successfully integrate operations that we have or may acquire or develop in the future; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment; general economic conditions; uncertainties about environmental issues and the related impact of such issues, including our environmental remediation plans; the impact of the new depreciation rates for Nicor Gas; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters, such as hurricanes, on the supply and price of natural gas; acts of war or terrorism; the outcome of litigation; and the factors described in this Item 1A, "Risk Factors" and the other factors discussed in our filings with the SEC.

There also may be other factors that we do not anticipate or that we do not recognize are material that could cause results to differ materially from expectations. Forward-looking statements speak only as of the date they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required by law.

Risks Related to Our Business

Our business is subject to substantial regulation by federal, state and local regulatory authorities. Adverse determinations by them and, in some instances, the absence of timely determinations, could adversely affect our business.

At the federal level, our business is regulated by the FERC. At the state level, our business is regulated by public service commissions or similar authorities, as well as local governing bodies with respect to certain issues.

Depending upon the jurisdiction, these regulatory authorities are generally entitled to review and approve many aspects of our operations, including the rates that we charge customers (including the recovery of costs for pipeline replacement and other capital projects), the rates of return on our equity investments in our operating companies, how we operate our business, and the interaction between our regulated operating companies and other subsidiaries that might provide products or services to those companies. In addition, our operating companies are generally subject to franchise agreements that entitle them to provide products and services.

While applicable law often provides a framework for the approvals that we need, the regulatory authorities generally have broad discretion. Moreover, in some jurisdictions, the regulatory process involves elected officials and is subject to inherent political issues, which can impact the approvals that we request. As a result, we may or may not be able to obtain the approvals that we request, the timing of obtaining those approvals can be uncertain, and the approvals can be subject to conditions that may or may not be favorable to our business. Should we not be able to obtain the rate increases that we request in a timely manner, should we not be able to fully recover the costs that we incur, or should we otherwise not obtain favorable approvals for the operation of our business, our business will be adversely impacted.

In addition, the regulatory environment in which we operate has increased in complexity over time, and further change is likely in many jurisdictions. These changes may or may not be favorable to our business. As the regulatory environment grows in complexity, inadvertent noncompliance is increasingly a greater risk. Noncompliance can, depending upon the circumstances, result in fines, penalties or other enforcement action by regulatory authorities, as well as damage our reputation and standing in the community, all of which would adversely impact our business.

Energy prices can fluctuate widely and quickly. To the extent that we have not anticipated and planned for those changes, our business can be adversely affected.

Recently, the price for natural gas and competing energy sources, such as oil, have fluctuated widely. Generally, we pass through changes in prices to the customers of our operating companies, and we have a process in place to continually review the adequacy of our utility gas rates and to take appropriate action with the applicable regulatory authorities. However, there is an inherent regulatory lag in adjusting rates and, in an increasing price environment, we have to bear the increased costs on an interim basis. We also have to incur additional financing costs as a result of purchasing more expensive gas.

In addition, increases in gas prices, both in absolute terms and relative to alternative energy sources, negatively impacts demand, the ability of customers to pay their utility bills and the timing of those payments (which lead to larger accounts receivable and greater bad debt expense) and various other factors. While the impact of some of these factors can be passed through to customers, there is generally a delay in that process that can adversely affect our business.

As noted below, for some portions of our business, we hedge the risk of price changes through the purchase of futures contracts and other means. These efforts, while designed to minimize the adverse impact of price changes, cannot assure that result. As a result, we retain exposure to price changes that can, in a volatile energy market, be extremely material and can adversely affect our business.

Variations in weather beyond what we have planned for can adversely impact our business.

A substantial portion of our revenue is derived from the transportation or sale of gas for space heating purposes. We plan for the demand of gas for this purpose based upon historical weather patterns and resulting demand. Where weather varies significantly beyond the range that we have planned for, it can impact us in many ways, including through increasing or decreasing the demand for gas, the cost of gas to us, and the availability, sufficiency and cost of transportation and storage capacity.

A decrease in the availability of adequate pipeline transportation capacity due to weather conditions or otherwise could adversely impact our business. We depend upon having access to adequate transportation and storage capacity for virtually all of our operations. A decrease in interstate pipeline capacity available to us, or an increase in competition for interstate pipeline transportation and storage capacity (e.g., even as a result of weather in regions that we do not significantly serve) could reduce our normal interstate supply of gas or cause rates to fluctuate.

We have WNA mechanisms for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas that partially offset the impact of unusually cold or warm weather on residential and commercial customer billings and on our operating margin, although at Elizabethtown Gas, we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10.3%. These WNA regulatory mechanisms are most effective in a reasonable temperature range relative to normal weather using historical averages. Outside of those ranges, our financial exposure is greater.

We also have decoupled rate designs, including straight-fixed-variable, at Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas that allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers. For more information, see Item 1, "Business" under the caption "Rate Structures" herein.

At Nicor Gas, approximately 60% of all usage is for space heating and approximately 75% of the usage and revenues occur from October through March. Weather fluctuations have the potential to significantly impact operating income and cash flow. For example, we estimate that a 100 degree-day variation from normal weather of 5,752 Heating Degree Days impacts Nicor Gas' margin, net of income taxes, by approximately $1 million under its current rate structure. For our weather risk associated with Nicor Gas, we utilize weather derivatives to reduce, but not eliminate, the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois. For more information, see Note 2 to the consolidated financial statements under Item 8 herein.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to mitigate the impact on its operating margin in the event of warmer or colder-than-normal weather in the winter months. However, these instruments do not fully mitigate the effects of unusually warm or cold weather.

Similarly, changes in weather conditions may also impact wholesale services' earnings. In addition to the impacts described above, weather impacts the ability of our wholesale services segment to capture value from location and seasonal spreads. Through the acquisition of natural gas and hedging of natural gas prices, wholesale services reduces some of the weather-related risks that it faces, but it cannot eliminate all of those risks.

Our retail energy businesses in Illinois, Nicor Solutions and Nicor Advanced Energy, offer utility-bill management products that mitigate and/or eliminate the risks of variations in weather to customers. We hedge this risk to reduce any adverse effects to us from weather variations.

We are subject to environmental regulation and our costs to comply are significant. Any changes in existing environmental regulation could adversely affect our business.

We are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations associated with storage, transportation, treatment and disposal of MGP residuals and waste in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to material fines, penalties or interruptions in our operations.

We are generally responsible for liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available, we manufactured gas from coal and other fuels. Those manufacturing operations were known as MGPs, which we ceased operating in the 1950s. A number of environmental issues may exist with respect to MGP's. For more information regarding these obligations, see Note 11 to the consolidated financial statements under Item 8 herein. Claims against us under environmental laws and regulations could result in material costs and liabilities.

Existing environmental laws and regulations could also be revised or reinterpreted, and new laws and regulations could be adopted or become applicable to us or our facilities. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties that could have a material adverse effect on our business.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions and replacements to our natural gas distribution systems to continue the expansion of our customer base and improve system reliability, especially during peak usage. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of such construction may be affected by the cost of obtaining government and other approvals, project delays, adequacy of supply of vendors, vendor performance, or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, the projected construction schedule and the completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of such construction. As a result, we may be required to fund a portion of our cash needs through borrowings, the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or it may impair our ability to complete the expansions or development projects.

We may be exposed to regulatory and financial risks related to the impact of climate change and associated legislation and regulation.

Climate change is expected to receive increasing attention from the current federal administration, non-governmental organizations and legislators. Debate continues as to the extent to which our climate is changing, the potential causes of any change and its potential impacts. Some attribute climate change to increased levels of greenhouse gases, including carbon dioxide and methane, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

The EPA has begun using provisions of the Clean Air Act to regulate greenhouse gas emissions, including carbon dioxide and methane, differently than under historical precedent. Thus far, EPA has imposed greenhouse gas regulations on automobiles and implemented new permitting requirements for the construction or modification of major stationary sources of greenhouse gas emissions, including natural gas-fired power plants.

In addition, President Obama issued a Presidential Memorandum on June 25, 2013, directing the EPA to adopt performance standards to regulate greenhouse gas emissions from power plants. Specifically, the Presidential Memorandum directs the EPA to propose standards for future power plants by September 20, 2013 and propose regulations and emission guidelines for modified, reconstructed, and existing power plants by June 1, 2014. The Presidential Memorandum directs the EPA to finalize those regulations by June 1, 2015. States would be required to develop regulations implementing the EPA's guidelines by June 30, 2016. It also includes a wide variety of other initiatives designed to reduce greenhouse gas emissions, prepare for the impacts of climate change, and lead international efforts to address climate change.

The outcome of federal and state actions to address climate change could potentially result in new regulations, additional charges to fund energy efficiency activities or other regulatory actions, which in turn could:

- result in increased costs associated with our operations,
- increase other costs to our business,
- affect the demand for natural gas (positively or negatively), and
- impact the prices we charge our customers and affect the competitive position of natural gas.

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

Any adoption of regulation by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on our business.

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

Our gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, including explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected, which may limit our ability to grow our business.

The natural gas business is highly competitive, increasingly complex, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our retail businesses is affected by competition from other energy marketers providing retail natural gas services in our service territories, most notably in Illinois and Georgia. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher natural gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our retail operations segment markets fixed-price and fixed-bill contracts that protect customers against higher natural gas prices, or protect customers against both higher natural gas prices and colder weather. The sale of these fixed-price contracts may be adversely affected if natural gas prices are, or are perceived to be, low and stable. Our retail operations segment also faces risks in the form of price, convenience and service competition from other warranty and HVAC companies.

Our wholesale services segment competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on our ability to aggregate competitively-priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our operating margin. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related operating margin available in this portion of Sequent’s business.

Our midstream operations segment competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Competition for our Central Valley storage facility in northern California primarily consists of storage facilities in northern California and western North America. Storage values have declined over the past several years due to low gas prices and low volatility, and we expect this to continue in 2015.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk at Nicor Gas, Atlanta Gas Light, SouthStar and Sequent.

Nicor Gas and Sequent often extend credit to counterparties. Despite performing credit analyses prior to extending credit and seeking to implement netting agreements, if the counterparties fail to perform and any collateral Nicor Gas or Sequent has secured is inadequate, we could experience material financial losses.

Further, Sequent has a concentration of credit risk with a limited number of parties. Most of this concentration is with counterparties that are either load-serving utilities or end-use customers that have supplied some level of credit support. Default by any of these counterparties in their obligations to pay amounts due to Sequent could result in credit losses that could be significant.

We have accounts receivable collection risks in Georgia due to a concentration of credit risks related to the provision of natural gas services to approximately 12 Marketers. As a result, Atlanta Gas Light depends on a limited number of customers for a significant portion of its revenues.

Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers’ bills and, consequently, impair customers’ ability to pay. For more information, see Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Credit Risk” herein.

The asset management arrangements between Sequent and our LDC’s, and between Sequent and its non-affiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent’s business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas and Elkton Gas. The profits it earns from the management of those assets with these affiliates are shared with their respective customers and for Atlanta Gas Light with the Georgia Commission’s Universal Service Fund, with the exception of Chattanooga Gas and Elkton Gas where Sequent is assessed annual fixed-fees. Entry into and renewal of these agreements are subject to regulatory approval, and we cannot predict whether such agreements will be renewed or the terms of such renewal.

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

We are exposed to market risk and may incur losses in wholesale services, midstream operations and retail operations.

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at midstream operations and SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. For more information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "VaR" herein.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect for wholesale services.

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were initiated.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the performance of investments, demographics, and various other factors and assumptions. These changes may have a material adverse effect on us.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics and assumptions, including longer life expectancy of beneficiaries and changes in health care cost trends. Any sustained declines in equity markets and reductions in bond yields will have an adverse effect on the value of our pension plan assets. In these circumstances, we may be required to recognize an increased pension expense and a charge to our other comprehensive income to the extent that the actual return on assets in the pension fund is less than the expected return. We may be required to make additional contributions in future periods in order to preserve the current level of benefits under the plans and in accordance with federal funding requirements.

For more information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Contractual Obligations and Commitments" and the subheading "Pension and Welfare Obligations" and Note 6 to the consolidated financial statements under Item 8 herein.

Natural disasters, terrorist activities and similarly unpredictable events could adversely affect our businesses.

Natural disasters may damage our assets, interrupt our business operations and adversely impact the demand for natural gas. Future acts of terrorism could be directed against companies operating in the U.S., and companies in the energy industry may face a heightened risk of exposure. The insurance industry has been disrupted by these types of events. As a result, the availability of insurance covering risks against which we and similar businesses typically insure may be limited or insufficient. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms. In addition, an employee or third party may purposely, or inadvertently, fail to adhere to our policies and procedures or our policies and procedures may not be effective; this could result in the violation of a law or regulation, a material error or misstatement, damage to our reputation or the incurrence of substantial expense.

Work stoppages could adversely impact our businesses.

Some of our businesses are dependent upon employees who are represented by unions and are covered by collective bargaining agreements. These agreements may increase our costs, affect our ability to continue offering market-based salaries and benefits, and limit our ability to implement efficiency-related improvements. Disputes with the unions could result in work stoppages that could impact the delivery of natural gas and other services, which could strain relationships with customers, vendors and regulators. We believe that we have a good working relationship with our unionized employees and we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the company and our employees. For more information, see Item 1, "Business" under the caption "Employees" herein.

Changes in laws and regulations regarding the sale and marketing of products and services offered by our retail operations segment could adversely affect our results of operations, cash flows and financial condition.

Our retail operations segment provides various energy-related products and services. These include sales of natural gas and utility-bill management services to residential and small commercial customers, and the sale, repair, maintenance and warranty of heating, air conditioning and indoor air quality equipment. The sale and marketing of these products and services are subject to various state and federal laws and regulations. Changes in these laws and regulations could impose additional costs on, restrict or prohibit certain activities, which could adversely affect our results of operations, cash flows and financial condition.

Conservation could adversely affect our results of operations, cash flows and financial condition.

As a result of legislative and regulatory initiatives on energy conservation, we have put into place programs to promote additional energy efficiency by our customers. Funding for such programs is being recovered through cost recovery riders. However, the adverse impact of lower deliveries and resulting reduced margin could adversely affect our results of operations, cash flows and financial condition.

A security breach could disrupt our operating systems, shutdown our facilities or expose confidential personal information.

Security breaches of our information technology infrastructure, including cyber-attacks, could lead to system disruptions or generate facility shutdowns. If a cyber-attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, a cyber-attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

Additionally, the protection of customer, employee and company data is critical to us. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and could expose us to liability to our customers, vendors, financial institutions and others. In addition, a breakdown or breach could also materially increase the costs we incur to protect against such risks. There is no guarantee that the procedures that we have implemented to protect against unauthorized access to secured data are adequate to safeguard against all data security breaches, although, to our knowledge, we did not have any material security breaches in 2014.

We may pursue acquisitions, divestitures and other strategic transactions, the success of which may impact our results of operations, cash flows and financial condition.

We have pursued acquisitions to complement or expand our business, divestures and other strategic transactions in the past and expect to in the future. If we identify an acquisition candidate, we may not be able to successfully negotiate or finance the acquisition or integrate the acquired businesses with our existing business and services. Acquisitions may result in dilutive issuances of equity securities and the incurrence of debt and contingent liabilities, amortization expenses and substantial goodwill. Acquisitions may not be accretive to our earnings and may cause dilution to our earnings per share, which may negatively affect the market price of our common shares. Any failure to successfully integrate businesses that we acquire in an efficient and effective manner could have a material adverse effect on us. Similarly, we may divest portions of our business, which may also have material and adverse effects.

We assess goodwill for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. We assess our long-lived assets, including finite-lived intangible assets, for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. To the extent the value of goodwill or long-lived assets become impaired, we may be required to incur impairment charges that could have a material impact on our results of operations. No impairment of goodwill was recorded as a result of our 2014 annual impairment testing, as the fair value of each reporting unit was in excess of the carrying value. Additionally, no impairment of long-lived assets was recorded during 2014.

Since interest rates are a key component, among other assumptions, in the models used to estimate the fair values of our reporting units, as interest rates rise, the calculated fair values decrease and future impairments may occur. Further, the rates for contracting capacity at Jefferson Island, Golden Triangle and Central Valley are also key components in the models used to estimate their fair value. Consequently, a further decline in market fundamentals and the rates for contracting availability could result in future impairments. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, we cannot provide assurance that future analyses will not result in impairment. These assumptions and estimates include projected cash flows, current and future rates for contracted capacity, growth rates, WACC and market multiples. For additional information, see Item 7,"Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Critical Accounting Policies and Estimates" herein.

Risks Related to Our Corporate and Financial Structure

We depend on access to the capital and financial markets to fund our business. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.

We rely on access to both short-term money markets (in the form of commercial paper and lines of credit) and long-term capital markets as sources of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be negatively affected, and we may be forced to postpone, modify or cancel capital projects. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from:

- adverse economic conditions;

- adverse general capital market conditions;
- poor performance and health of the utility industry in general;
- bankruptcy or financial distress of unrelated energy companies or marketers;
- significant decrease in the demand for natural gas;
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business;
- terrorist attacks on our facilities or our suppliers; or
- extreme weather conditions.

The amount of our working capital requirements in the near term will primarily depend on the market price of natural gas and weather. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations.

While we believe we can meet our capital requirements from our operations and our available sources of financing, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near term. The future effects on our business, liquidity and financial results due to market disruptions could be material and adverse to us, both in the ways described above or in ways that we do not currently anticipate.

A downgrade in our credit rating would require us to pay higher interest rates and could negatively affect our ability to access capital, or may require us to provide additional collateral to certain counterparties.

Our senior debt is currently assigned investment grade credit ratings. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we would be required to provide additional collateral to continue conducting business with certain customers. For additional credit rating and interest rate information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity and Capital Resources" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" herein.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense and adversely affect our earnings.

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. For additional information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" herein. However, we may not structure these swap agreements in a manner that manages our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

We are a holding company and are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need.

A significant portion of our outstanding debt was issued by our wholly owned subsidiary, AGL Capital, which we fully and unconditionally guarantee. Since we are a holding company and have no operations separate from our investment in our subsidiaries, we are dependent on the net income and cash flows of our subsidiaries and their ability to pay upstream dividends or other distributions to meet our financial obligations and to pay dividends on our common stock. The ability of our subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. In addition, Nicor Gas is not permitted to make money pool loans to affiliates. Refer to Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" herein for additional information.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivative instruments, including futures, options, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In addition, derivative contracts entered into for hedging purposes may not offset 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 derivative instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the reported fair values of these contracts.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.

Our credit facilities contain cross-default provisions. Should an event of default occur under some of our debt agreements, we face the prospect of being in default under our other debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

ITEM 2. PROPERTIES

We consider our properties to be well maintained, in good operating condition and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by our segments. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 8 to our consolidated financial statements under Item 8 herein.

Distribution and transmission mains

Our distribution systems transport natural gas from our pipeline suppliers to customers in our service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters and regulators. At December 31, 2014, our distribution operations segment owned approximately 80,700 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair, and believe that our distribution systems are in good condition.

Storage assets

Distribution Operations We own and operate eight underground natural gas storage facilities in Illinois with a total inventory capacity of about 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. The system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of its normal winter deliveries in Illinois. This level of storage capability provides us with supply flexibility, improves the reliability of deliveries and can help mitigate the risk associated with seasonal price movements.

We have five LNG plants located in Georgia, New Jersey and Tennessee with LNG storage capacity of approximately 7.6 Bcf. In addition, we own one propane storage facility in Virginia with a storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by our distribution operations segment to supplement natural gas supply during peak usage periods.

Midstream Operations We own three high-deliverability natural gas storage and hub facilities that are operated by our midstream operations segment. Jefferson Island operates a storage facility in Louisiana currently consisting of two salt dome gas storage caverns. Golden Triangle operates a storage facility in Texas consisting of two salt dome caverns. Central Valley operates a depleted field storage facility in California. In addition, we have an LNG facility in Alabama that produces LNG for Pivotal LNG, a wholly owned subsidiary, to support its business of selling LNG as a substitute fuel in various markets. For additional information on our storage facilities, see Item 1, "Business" under the caption "Midstream Operations" herein.

Offices

All of our reportable segments own or lease office, warehouse and other facilities throughout our operating areas. We expect additional or substitute space to be available as needed to accommodate the expansion of our operations.

ITEM 3. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party as both plaintiff and defendant to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations.

For more information regarding our regulatory proceedings and litigation, see Note 11 to our consolidated financial statements under the caption "Litigation" under Item 8 herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the ticker symbol GAS. At February 4, 2015, there were 21,551 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2014 and 2013 is as follows:

	Sales price of common stock		Cash dividend per common
Quarter ended:	**High**	**Low**	**share**
March 31, 2014	$49.84	$45.17	$0.49
June 30, 2014	55.10	48.29	0.49
September 30, 2014	55.30	48.72	0.49
December 31, 2014	56.67	50.10	0.49
			$1.96

	Sales price of common stock		Cash dividend per common
Quarter ended:	**High**	**Low**	**share**
March 31, 2013	$42.37	$38.86	$0.47
June 30, 2013	44.85	41.21	0.47
September 30, 2013	47.00	41.94	0.47
December 31, 2013	49.31	44.56	0.47
			$1.88

We have paid 268 consecutive quarterly dividends to our common shareholders beginning in 1948, historically four times each year: March 1, June 1, September 1 and December 1. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Cash Flow from Financing Activities - Dividends on Common Stock" herein. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants, and
- our ability to satisfy our obligations to any future preferred shareholders.

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

- we could not pay our debts as they become due in the usual course of business, or
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy (upon dissolution) the preferential rights of shareholders whose rights are superior to those of the shareholders receiving the dividends.

Issuer Purchases of Equity Securities

There were no purchases of our common stock by us or any affiliated purchasers during the three months ended December 31, 2014.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below which should be read in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data" herein. Additionally, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein for a discussion of the primary factors impacting the changes in our results of operations for the periods reflected in our Consolidated Statements of Income. The operations of our former Tropical Shipping business, which was sold during 2014, are reflected as discontinued operations and all prior periods have been recast to reflect the discontinued operations. Material changes from 2013 to 2014 are due primarily to earnings from our wholesale services segment, resulting mainly from colder-than-normal weather and associated natural gas price volatility in 2014. Material changes from 2011 to 2012 are primarily due to the Nicor merger, which closed on December 9, 2011.

Dollars and shares in millions, except per share amounts	**2014**	**2013**	**2012**	**2011**	**2010**
Income statement data					
Operating revenues	$5,385	$4,209	$3,562	$2,305	$2,373
Operating expenses					
Cost of goods sold	2,765	2,110	1,583	1,085	1,164
Operation and maintenance (1)	939	887	816	497	497
Depreciation and amortization	380	397	394	182	160
Nicor merger expenses (1)	-	-	20	57	6
Taxes other than income taxes	208	187	159	57	46
Total operating expenses	4,292	3,581	2,972	1,878	1,873
Gain on disposition of assets	2	11	-	-	-
Operating income	1,095	639	590	427	500
Other income (expense)	14	16	24	7	(1)
EBIT	1,109	655	614	434	499
Interest expense, net	179	170	183	134	109
Income before income taxes	930	485	431	300	390
Income tax expense	350	177	157	121	140
Income from continuing operations	580	308	274	179	250
(Loss) income from discontinued operations, net of tax	(80)	5	1	-	-
Net income	500	313	275	179	250
Less net income attributable to the noncontrolling interest	18	18	15	14	16
Net income attributable to AGL Resources Inc.	$482	$295	$260	$165	$234
Amounts attributable to AGL Resources Inc.					
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259	$165	$234
(Loss) income from discontinued operations, net of tax	(80)	5	1	-	-
Net income attributable to AGL Resources Inc.	$482	$295	$260	$165	$234
Per common share information					
Diluted weighted average common shares outstanding	119.2	118.3	117.5	80.9	77.8
Diluted earnings (loss) per common share					
Continuing operations	$4.71	$2.45	$2.20	$2.04	$3.00
Discontinued operations	(0.67)	0.04	0.01	-	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21	$2.04	$3.00
Dividends declared per common share	$1.96	$1.88	$1.74	$1.90	$1.76
Dividend payout ratio	49%	76%	79%	93%	58%
Dividend yield (2)	3.6%	4.0%	4.4%	4.5%	4.9%
Price range:					
High	$56.67	$49.31	$42.88	$43.69	$40.08
Low	$45.17	$38.86	$36.59	$34.08	$34.21
Close (3)	$54.51	$47.23	$39.97	$42.26	$35.85
Market value (3)	$6,522	$5,615	$4,711	$4,946	$2,800
Statements of Financial Position data (3)					
Total assets (4)	$14,909	$14,550	$14,070	$13,862	$7,481
Property, plant and equipment – net	9,090	8,643	8,205	7,741	4,396
Long-term debt	3,802	3,813	3,553	3,578	1,971
Total equity	3,828	3,613	3,391	3,305	1,809
Financial ratios (3)					
Debt	57%	58%	59%	60%	60%
Equity	43%	42%	41%	40%	40%
Total	100%	100%	100%	100%	100%
Return on average equity	13.0%	8.4%	7.8%	6.4%	12.9%

(1) Transaction expenses associated with the Nicor merger were excluded from operation and maintenance expenses and presented separately.
(2) Dividends declared per common share during the fiscal period divided by market value per common share as of the last day of the fiscal period.
(3) As of the last day of the fiscal period.
(4) Amounts for all periods include assets held for sale, which reflect the assets of our former Tropical Shipping business.

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

Executive Summary

We are an energy services holding company whose principal business is the distribution of natural gas in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland – through our seven natural gas distribution utilities. We are also involved in several other businesses that are complementary to the distribution of natural gas. We have four reportable segments that consist of the following – distribution operations, retail operations, wholesale services and midstream operations – and one non-reportable segment – other. These segments are consistent with how management views and operates our business. Amounts shown in this Item 7, unless otherwise indicated, exclude assets held for sale and discontinued operations. See Note 14 to our consolidated financial statements under Item 8 herein for additional information. The following table provides certain information on our segments.

	EBIT			Assets			Capital expenditures		
	2014 (1)	2013	2012	2014	2013	2012	2014	2013	2012
Distribution operations	52%	84%	84%	81%	82%	82%	93%	93%	84%
Retail operations	12	20	18	5	5	4	1	1	1
Wholesale services	38	-	-	9	8	9	-	-	-
Midstream operations	(1)	(2)	2	5	5	5	2	2	8
Other/intercompany eliminations	(1)	(2)	(4)	-	-	-	4	4	7
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

(1) The EBIT in 2014 was impacted by significantly higher-than-normal commercial activity realized in wholesale services, which is not indicative of future performance.

In the third quarter of 2014, we adjusted the accounting treatment for our previously reported non-cash revenue recognition associated with our regulatory infrastructure programs in our distribution operations segment. The adjustments did not affect previously reported operating cash flows, nor are they expected to affect capital expenditure plans or dividend payments. We do not expect these adjustments to impact the levels of return from our infrastructure replacement programs, as all amounts will be recovered in accordance with allowed recovery mechanisms. The adjustments relate only to the timing of recognition and do not impact rates charged to customers. Additionally, we adjusted the amortization of intangible assets for customer relationships and trade names in our retail operations segment to reflect the amortization expense on a basis consistent with the pattern of undiscounted cash flows used to determine their fair values. In November 2014, we amended our 2013 Form 10-K and our Forms 10-Q for the quarters ended March 31, 2014 and June 30, 2014 to revise our financial statements to reflect these adjustments. Our prior-period financial statements included herein reflect these adjustments.

In September 2014, we closed on the sale of Tropical Shipping and received after-tax cash proceeds of approximately $225 million, as well as repatriated $86 million in cash. The transaction resulted in expenses, including taxes, of approximately $80 million or $(0.67) per share in 2014. Tropical Shipping operated as part of our cargo shipping segment and the financial results are classified as discontinued operations. Accordingly, all references to continuing operations exclude the operations of Tropical Shipping. The sale of Tropical Shipping allows us to focus on growing our core business of operating regulated utilities and complementary non-regulated energy businesses and provided us with flexibility around our near-term financing plans. For additional information on our discontinued operations, see Note 14 to our consolidated financial statements under Item 8 herein.

In 2014, our net income from continuing operations was $580 million, an increase of $272 million compared to income from continuing operations in 2013. This increase was primarily the result of significantly higher commercial activity and net hedge gains at wholesale services, mainly due to natural gas market volatility. This volatility was primarily generated by significantly colder-than normal weather in the first quarter of 2014, which also increased the operating margins at distribution operations and retail operations. Excluding the favorable weather impacts, we also achieved growth in our operating margins during 2014 as a result of targeted acquisition growth in retail operations. Our operating expenses in 2014 were higher compared to 2013 mainly as a result of higher incentive compensation expenses primarily related to higher earnings in 2014.

Our priorities for 2015 are consistent with the direction we have taken the company over the last several years. We will remain focused on efficient operations across all of our businesses, including offsetting inflationary pressures by aggressive cost controls, spreading costs across a broader customer base and sizing our operations to properly reflect market conditions. Several of our specific business objectives are detailed as follows:

- **Distribution Operations**: Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand the system and capitalize on potential customer conversions. We intend to continue investing in our regulatory infrastructure programs in Georgia, Virginia, New Jersey and Tennessee to minimize regulatory lag and the recovery cycle. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we will implement rates under the program effective in March 2015.

We continue to effectively manage costs and leverage our shared services model across our businesses to largely overcome inflationary effects.

- **Retail Operations**: Maintain operating margins in Georgia and Illinois while continuing to expand into other profitable retail markets; expand our warranty businesses through partnership opportunities with our affiliates. We expect the Georgia retail market to remain highly competitive; however, our operating margins are forecasted to remain stable with modest growth and expansion into new markets.
- **Wholesale Services**: Maximize storage and transportation positions; effectively perform on existing asset management agreements, and expand customer base and maintain cost structure in line with market fundamentals. We anticipate volatility to remain low to moderate in certain areas of our portfolio; however, we expect near-term volatility in the supply-constrained Northeast corridor until expected new pipeline projects are completed and new capacity is placed into service. We continue to position our business to secure sufficient supplies of natural gas to meet the needs of our utility and third-party customers and to hedge natural gas prices to manage costs effectively, reduce price volatility and maintain a competitive advantage.
- **Midstream Operations**: Optimize storage portfolio, including contracts that have expired or will expire, pursue LNG transportation and natural gas pipeline opportunities and evaluate alternate uses for our storage facilities. In 2014, we announced our participation in three pipeline projects that we expect to provide a diverse source of natural gas to our customers in Georgia, New Jersey and Virginia. Subject to regulatory approvals, construction is expected to begin in the 2016-2017 timeframe with completion targeted in 2017-2018. For additional information on our pipeline projects, see Note 2 and Note 10 to our consolidated financial statements under Item 8 herein and Item 1, "Business" under the caption "Midstream Operations."

Additionally, we will maintain our strong balance sheet and liquidity profile, solid investment grade ratings and our commitment to sustainable annual dividend growth. For additional information on our reportable segments, see Note 13 to our consolidated financial statements under Item 8 herein and Item 1, "Business."

Results of Operations

We generate the majority of our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed to residential, commercial and industrial customers from the date of the last bill to the end of the reporting period. No individual customer or industry accounts for a significant portion of our revenues. The following table provides more information regarding the components of our operating revenues.

In millions	**2014**	**2013**	**2012**
Residential	$2,877	$2,422	$2,011
Commercial	861	696	656
Transportation	458	487	474
Industrial	242	180	262
Other (1)	947	424	159
Total operating revenues	$5,385	$4,209	$3,562

(1) Includes significantly higher-than-normal revenues at wholesale services in 2014, which are not indicative of future performance.

We evaluate segment performance using the measures of EBIT and operating margin. EBIT includes operating income and other income and expenses. Items that we do not include in EBIT are financing costs, including interest expense and income taxes, each of which we evaluate on a consolidated basis. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of goods sold and revenue tax expense in distribution operations. Operating margin excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets. These items are included in our calculation of operating income as reflected in our Consolidated Statements of Income.

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of goods sold and revenue tax expenses can vary significantly and are generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail operations, wholesale services and midstream operations segments since it is a direct measure of operating margin before overhead costs. You should not consider operating margin an alternative to, or a more meaningful indicator of, our operating performance than operating income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, operating margin may not be comparable to similarly titled measures of other companies.

We also believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses and the additional accrual for the Nicor Gas PBR issue, provides investors with an additional measure of our performance. Adjusted basic and diluted earnings per share should not be considered an alternative to, or a more meaningful indicator of, our operating performance than our GAAP basic and diluted earnings per share. The following table reconciles operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income and our GAAP basic and diluted earnings per common share to our non-GAAP basic and diluted earnings per share – as adjusted, together with other consolidated financial information for the last three years.

In millions, except per share amounts	**2014**	**2013**	**2012**
Operating revenues	$5,385	$4,209	$3,562
Cost of goods sold	(2,765)	(2,110)	(1,583)
Revenue tax expense (1)	(130)	(110)	(85)
Operating margin	2,490	1,989	1,894
Operating expenses	(1,527)	(1,471)	(1,369)
Revenue tax expense (1)	130	110	85
Gain on disposition of assets	2	11	-
Nicor merger expenses	-	-	(20)
Operating income	1,095	639	590
Other income	14	16	24
EBIT	1,109	655	614
Interest expense, net	(179)	(170)	(183)
Income before income taxes	930	485	431
Income tax expense	(350)	(177)	(157)
Income from continuing operations	580	308	274
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income	500	313	275
Less net income attributable to the noncontrolling interest	18	18	15
Net income attributable to AGL Resources Inc.	$482	$295	$260
Amounts attributable to AGL Resources Inc.			
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Per common share data			
Diluted earnings per common share from continuing operations	$4.71	$2.45	$2.20
Diluted (loss) earnings per common share from discontinued operations (2)	(0.67)	0.04	0.01
Additional accrual for Nicor Gas PBR issue	-	-	0.04
Transaction costs of Nicor merger	-	-	0.11
Diluted earnings per share - as adjusted	$4.04	$2.49	$2.36

(1) Adjusted for Nicor Gas' revenue tax expenses, as they are passed through directly to customers.
(2) In September 2014, we closed on the sale of Tropical Shipping. See Note 14 to our consolidated financial statements under Item 8 herein for additional information.

In 2014, our income from continuing operations attributable to AGL Resources Inc. increased by $272 million, or 94% compared to 2013. This increase was primarily the result of the following:

- Significantly higher commercial activity primarily in the first quarter of 2014, and mark-to-market hedge gains, net of LOCOM adjustments at wholesale services in 2014 from price volatility generated by colder-than-normal weather, which increased operating margin by $462 million compared to 2013.
- Increased operating margin at distribution operations and retail operations of $50 million mainly due to significantly colder-than-normal weather in 2014 compared to slightly colder-than-normal weather in 2013, as well as customer usage and customer growth. We also achieved growth as a result of our 2013 acquisitions and expansion into additional markets at retail operations.
- These increases were partially offset by a decrease in margin of $10 million at midstream operations primarily due to a retained fuel true-up at one of our storage facilities as a result of naturally occurring shrinkage of the caverns, as well as lower contracted firm rates at Jefferson Island and Central Valley.
- Favorability year-over-year was negatively impacted by higher incentive compensation expenses primarily related to higher earnings in 2014 and increased outside services expenses of $49 million, and the $8 million higher pre-tax gain in 2013 related to the sale of Compass Energy.
- Our income tax expense from continuing operations increased by $173 million for 2014 compared to 2013, primarily due to higher consolidated earnings. The increase was primarily a result of increased earnings at wholesale services.

In 2013, our income from continuing operations attributable to AGL Resources Inc. increased by $31 million, or 12% compared to 2012.

- The overall increase was primarily the result of increased operating margin at distribution operations and retail operations due to weather that was both colder-than-normal and colder than the prior year, increased regulatory infrastructure program revenues at Atlanta Gas Light, the acquisition of service contracts and residential and commercial energy customer relationships in our retail operations segment, as well as lower depreciation expense at Nicor Gas.

- The increase was unfavorably impacted by mark-to-market accounting hedge losses in our wholesale services segment during the second half of 2013, offset by higher commercial activity and the $11 million pre-tax gain on the sale of Compass Energy in 2013.
- Our midstream operations segment was unfavorable compared to 2012 due to the $8 million loss associated with the termination of the Sawgrass Storage project in 2013, as well as lower contracted firm rates at Jefferson Island and higher operating expenses at Golden Triangle, Central Valley and Pivotal LNG resulting from full year operations in 2013 as compared to partial year operations in 2012.
- Favorability year-over-year was also partially offset by higher incentive compensation expenses in most of our businesses, as our incentive compensation expense was above targeted levels in 2013 based on improved financial and operational performance compared to significantly below targeted annual levels in 2012 due to below target performance. In addition, our bad debt expense increased at distribution operations and retail operations primarily as a result of higher revenues from colder weather combined with natural gas prices that were higher than the prior year.
- In 2012, we recorded $20 million ($13 million net of tax) of Nicor merger-related expenses.
- In 2013, our interest expense decreased by $13 million compared to 2012. This decrease was the result of overall lower interest rates mostly offset by higher average debt outstanding primarily as a result of issuing $500 million of senior notes in place of variable-rate debt.
- In 2013, our income tax expense increased by $20 million or 13% compared to 2012 primarily due to higher consolidated earnings, as previously discussed.

The variances for each reportable segment are contained within the year-over-year discussion on the following pages.

Operating metrics

Weather We measure the effects of weather on our business primarily through Heating Degree Days, and we also consider operating costs that may vary with the effects of weather. Generally, increased Heating Degree Days result in higher demand for gas on our distribution systems. With the exception of Nicor Gas and Florida City Gas, we have various regulatory mechanisms, such as weather normalization mechanisms, which limit our exposure to weather changes within typical ranges in each of our utilities' respective service areas. However, our customers in Illinois and our retail operations customers in Georgia can be impacted by warmer or colder-than-normal weather. We have presented the Heating Degree Day information for those locations in the following table.

	Normal (1)	2014	2013	2012	2014 vs. 2013 colder (warmer)	2013 vs. 2012 colder (warmer)	2014 vs. normal colder (warmer)	2013 vs. normal colder (warmer)	2012 vs. normal colder (warmer)
Year ended December 31,									
Illinois (2)	5,752	6,556	6,305	4,863	4%	30%	14%	10%	(15)%
Georgia	2,599	2,882	2,689	1,934	7%	39%	11%	3%	(26)%
Quarter ended December 31,									
Illinois (2)	2,085	2,103	2,383	1,890	(12)%	26%	1%	14%	(9)%
Georgia	1,014	1,003	1,049	878	(4)%	19%	(1)%	3%	(13)%

(1) Normal represents the 10-year average from January 1, 2004 through December 31, 2013, for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, as obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(2) The 10-year average Heating Degree Days established by the Illinois Commission in our last rate case, is 2,020 for the fourth quarter and 5,600 for the 12 months from 1998 through 2007.

In 2014, we experienced weather in Illinois that was 14% colder-than-normal and 4% colder than 2013. This weather positively impacted our 2014 EBIT at our utilities, primarily at Nicor Gas, by $20 million, and drove an increase of $12 million in 2013 based on 10-year normal weather. Georgia also experienced 11% colder-than-normal weather, and 7% colder weather than the same period last year. Colder-than-normal weather increased EBIT at retail operations by $14 million in 2014 and $9 million in 2013 compared to expected levels based on 10-year normal weather.

Customers The number of customers at distribution operations and energy customers at retail operations can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Our energy customers at retail operations are primarily located in Georgia and Illinois. Our customer metrics highlight the average number of customers to which we provide services and are presented in the following table.

	Years ended December 31,			2014 vs. 2013 change		2013 vs. 2012 change	
(in thousands)	2014	2013	2012	#	%	#	%
Distribution operations customers (1)	4,497	4,479	4,459	18	0.4%	20	0.4%
Retail operations							
Energy customers (2)	628	619	623	9	1%	(4)	(1)%
Service contracts (3)	1,182	1,127	684	55	5%	443	65%
Market share in Georgia	31%	31%	32%		-%		(1)%

(1) In 2014, we implemented a process change at Nicor Gas that adversely impacted our customer count. This had the effect of immaterial growth for Nicor Gas from last year. Excluding Nicor Gas, our customer growth rate for 2014 was 0.8%.
(2) Increase from 2013 to 2014 primarily due to the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013.
(3) Increase from 2012 to 2013 primarily due to acquisition of approximately 500,000 contracts on January 31, 2013.

We anticipate overall utility customer growth trends for 2014 to continue in 2015 based on an expectation of continuing improvement in the economy and relatively low natural gas prices. We use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include adding residential customers, multifamily complexes and commercial and industrial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new natural gas related programs, products and services to enhance customer growth, mitigate customer attrition and increase operating revenues. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. We also target customer conversions to natural gas from other energy sources, emphasizing the pricing advantage of natural gas. These programs focus on premises that could be connected to our distribution system at little or no cost to the customer. In cases where conversion cost can be a disincentive, we may employ rebate programs and other assistance to address customer cost issues.

In 2015, we intend to continue efforts in our retail operations segment to enter into targeted markets and expand energy customers and its service contracts. We anticipate this expansion will provide growth opportunities in future years.

Volume Our natural gas volume metrics for distribution operations and retail operations present the effects of weather and customers' demand for natural gas compared to the prior year. Wholesale services' daily physical sales volumes represent the daily average natural gas volumes sold to its customers. Our volume metrics are presented in the following table:

	Year ended December 31,				
Distribution operations (In Bcf)	**2014**	**2013**	**2012**	**2014 vs. 2013 % change**	**2013 vs. 2012 % change**
Firm (1)	766	720	606	6%	19%
Interruptible	106	111	107	(5)%	4%
Total	872	831	713	5%	17%
Retail operations (In Bcf)					
Georgia firm	41	38	31	8%	23%
Illinois	17	9	8	89%	13%
Other (includes Florida, Maryland, New York and Ohio)	10	8	8	25%	-
Wholesale services					
Daily physical sales (Bcf/day)	6.32	5.73	5.54	10%	3%

(1) Year-over-year increases are primarily a result of colder weather.

Within our midstream operations segment, our natural gas storage businesses seek to have a significant portion of their working natural gas capacity under firm subscription, but also take into account current and expected market conditions. This allows our natural gas storage business to generate additional revenue during times of peak market demand for natural gas storage services, but retain some consistency with their earnings and maximize the value of the investments.

Our midstream operations storage business is cyclical, and the abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. Consistent with our expectations, we had contracts expire in 2014 that were re-subscribed at lower prices as compared to prior years. We anticipate these lower natural gas prices to continue in 2015 as compared to historical averages. We expect the rates at which we re-contract expiring capacity in 2015 to be marginally higher than re-contracting rates in 2014, but still significantly below historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy continues to improve, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. As of the periods presented, the overall monthly average firm subscription rates per facility and amount of firm capacity subscription were as follows:

	December 31, 2014		**December 31, 2013**	
	Avg. rates (1)	**Firm capacity under subscription** (1)	**Avg. rates** (1)	**Firm capacity under subscription** (1)
Jefferson Island	$0.108	4.6	$0.122	5.6
Golden Triangle	0.114	5.0	0.240	2.0
Central Valley	0.062	2.5	0.130	3.0

(1) Rates are per dekatherm. Firm capacity under subscription excludes 7 Bcf contracted by Sequent as of December 31, 2014, at an average monthly rate of $0.050 and 3.5 Bcf as of December 31, 2013, at an average monthly rate of $0.091.

Segment information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the last three years.

	Operating Margin (1) (2)			**Operating Expenses** (2) (3)			**EBIT** (1)		
In millions	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013** (4)	**2012**
Distribution operations	$1,648	$1,615	$1,552	$1,075	$1,083	$1,044	$581	$546	$517
Retail operations	311	294	247	179	162	136	132	132	111
Wholesale services	501	39	50	79	53	54	422	(3)	(3)
Midstream operations	31	41	46	50	46	38	(17)	(10)	10
Other (5)	7	8	7	22	25	40	(9)	(10)	(21)
Intercompany eliminations	(8)	(8)	(8)	(8)	(8)	(8)	-	-	-
Consolidated	$2,490	$1,989	$1,894	$1,397	$1,361	$1,304	$1,109	$655	$614

(1) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income, and EBIT to earnings before income taxes and net income is contained in “Results of Operations” herein. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information.
(2) Operating margin and operating expenses are adjusted for revenue tax expenses, which are passed through directly to our customers.
(3) Includes $20 million in Nicor merger transaction expenses for 2012 and an $8 million accrual in 2012 for the Nicor Gas PBR issue.
(4) EBIT for 2013 includes an $11 million pre-tax gain on sale of Compass Energy in our wholesale services segment and an $8 million pre-tax loss associated with the termination of the Sawgrass Storage project within our midstream operations segment.
(5) Our “other” non-reportable segment includes our investment in Triton, which was formerly part of our cargo shipping segment that is now classified as discontinued operations. See Note 14 to our consolidated financial statements under Item 8 herein for additional information.

During the Heating Season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale services operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain Consolidated Statements of Financial Position items across quarters, including receivables, unbilled revenue, inventories and short-term debt. However, these items are comparable when reviewing our annual results. Our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality. The EBIT of our distribution operations, retail operations and wholesale services segments are seasonal, as indicated in the table below.

% generated during Heating Season

	Revenues	**EBIT**
2014	73%	81%
2013	68	72
2012	70	76

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our second largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers’ ability to pay for gas consumed. We have various mechanisms, such as weather normalization mechanisms at our utilities and weather derivative instruments that limit our exposure to weather changes within typical ranges in their respective service areas.

In millions	2014	2013
EBIT - prior year	**$546**	**$517**
Operating margin		
Increase mainly driven by non-weather-related customer usage and customer growth	22	9
Increased margin as a result of higher customer usage due to colder-than-normal weather	13	36
Increase from regulatory infrastructure programs, primarily at Atlanta Gas Light	10	4
(Decrease) increase primarily as a result of bad debt and energy efficiency program recoveries at Nicor Gas	(12)	19
Decreased gas storage carrying amounts at Atlanta Gas Light	-	(5)
Increase in operating margin	**33**	**63**
Operating expenses		
Decreased depreciation expense primarily due to the impact of Nicor Gas' new composite depreciation rate effective August 30, 2013, partially offset by increased PP&E from infrastructure additions and improvements	(22)	(8)
Decreased benefit expenses primarily related to lower pension costs due to change in actuarial gains and losses	(13)	(6)
(Decreased) increased rider expenses primarily as a result of energy efficiency program expenses at Nicor Gas	(12)	19
Increased payroll and variable compensation costs as a result of merit increases and higher earnings	19	37
Increased outside services and other expenses mainly as a result of maintenance programs	11	1
Increase due to weather-related expenses	5	-
Increased bad debt expenses related to colder-than-normal weather primarily at Elizabethtown Gas	4	4
Decreased operation and maintenance expense at Nicor Gas related to the 2012 PBR accrual	-	(8)
(Decrease) increase in operating expenses	**(8)**	**39**
(Decrease) increase in other income primarily from STRIDE Projects at Atlanta Gas Light	**(6)**	**5**
EBIT - current year	**$581**	**$546**

Retail Operations

Our retail operations segment, which consists of several businesses that provide energy-related products and services to retail markets, is also weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. During 2014, our retail operations' EBIT was negatively impacted by $16 million of unrealized hedge losses and LOCOM adjustments.

In millions	2014	2013
EBIT - prior year	**$132**	**$111**
Operating margin		
Increase due to acquisitions in January and June 2013	9	35
Increase primarily related to customer usage in Georgia and Illinois due to colder-than-normal weather, net of weather hedges	8	18
Increase primarily related to warranty service contract count and price increases	6	-
Increase primarily related to non-weather related customer usage and customer growth	5	1
Increase (decrease) related to change in gas costs and from retail price spreads	5	(11)
Change in value of derivatives as a result of changes in NYMEX natural gas prices	(13)	1
Change in LOCOM adjustment, net of recoveries	(3)	3
Increase in operating margin	**17**	**47**
Operating expenses		
Increased variable compensation costs, outside services, marketing and other	11	-
Increased due to weather-related expenses	3	-
Increased bad debt expenses primarily related to higher natural gas prices	2	3
Increased expenses primarily due to acquisitions in January and June 2013	1	23
Increase in operating expenses	**17**	**26**
EBIT - current year	**$132**	**$132**

Wholesale Services

Our wholesale services segment is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services and wholesale marketing. We have positioned the business to generate positive economic earnings even under low volatility market conditions. However, when market price volatility increases as we experienced in 2014, we are well positioned to capture significant value and generate stronger results. Results in 2014 for the wholesale services segment were the best in the company's history and not indicative of future performance. EBIT for our wholesale services segment is impacted by volatility in the natural gas market arising from a number of factors, including weather fluctuations and changes in supply or demand for natural gas in different regions of the country. We principally use physical and financial arrangements to reduce the risks associated with fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, our reported earnings for wholesale services reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues.

In millions	2014	2013
EBIT - prior year	**$(3)**	**$(3)**
Operating margin		
Change in commercial activity largely driven by the transportation and storage portfolios in the Northeast and Midwest	319	90
Change in value of transportation and forward commodity derivatives from price movements related to natural gas transportation positions	111	(70)
Change in value of storage derivatives as a result of changes in NYMEX natural gas prices	102	(30)
Change in LOCOM adjustment, net of estimated current period recoveries	(66)	3
Decrease due to sale of Compass Energy in May 2013	(4)	(4)
Increase (decrease) in operating margin	**462**	**(11)**
Operating expenses		
Increased variable compensation expenses related to higher earnings and slightly higher other costs in 2014	28	3
Decrease due to sale of Compass Energy in May 2013	(2)	(4)
Increase (decrease) in operating expenses	**26**	**(1)**
(Decrease) increase in other income, primarily related to the gain on sale of Compass Energy	(11)	10
EBIT - current year	**$422**	**$(3)**

The following table illustrates the components of wholesale services' operating margin for the periods presented.

In millions	2014	2013	2012
Commercial activity recognized	$444	$129	$43
Gain (loss) on transportation and forward commodity derivatives	38	(73)	(3)
Gain (loss) on storage derivatives	86	(16)	14
Inventory LOCOM adjustment, net of estimated current period recoveries	(67)	(1)	(4)
Operating margin	$501	$39	$50

Change in commercial activity The commercial activity at wholesale services includes recognized storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur in the period. Additionally, the commercial activity includes operating margin generated and recognized in the current period. For 2014, commercial activity increased significantly due to:

- the recognition of significantly higher operating margin associated with our transportation and storage portfolios, particularly in the Northeast and Midwest regions, from price volatility generated by significantly colder-than-normal weather in 2014, in part reflecting Sequent's strategy and focus on providing asset management and related services to producers around the major shale-producing regions and to natural gas-fired power generators, enabling Sequent to optimize the associated pipeline transportation and storage capacity assets
- the recognition of operating margin resulting from the withdrawal of storage inventory hedged at the end of 2013 that was included in the storage withdrawal schedule with a value of $28 million as of December 31, 2013
- the recognition of operating margin resulting from mark-to-market accounting derivative losses at the end of 2013

The 2013 change in commercial activity was primarily due to increased cash optimization opportunities related to constraints of natural gas purchased from producers in the Northeastern U.S. Commercial activity in 2013 was also impacted by the recognition of operating margin resulting from the withdrawal of storage inventory hedged at the end of 2012 that was included in the storage withdrawal schedule with a value of $27 million as of December 31, 2012. Additionally, increased volatility associated with colder weather contributed to the increase in commercial activity.

Change in storage and transportation derivatives A return of significantly higher price volatility in 2014 benefitted Sequent's portfolio of pipeline transportation and storage capacity assets throughout the country, primarily in the Gulf Coast, Northeast and Midwest markets. Storage derivative gains in 2014 are primarily due to the change in natural gas prices applicable to the locations of our specific storage assets. These increases were partially offset by a $66 million increase in the required LOCOM adjustment to natural gas inventories for the year ended December 31, 2014, net of estimated hedging recoveries.

Gains in our transportation and forward commodity derivative positions in 2014 are primarily the result of narrowing transportation basis spreads. Significantly colder-than-normal weather and higher demand together with natural gas transportation constraints due to growing shale production impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast and the Midwest regions, during 2014. Transportation and forward commodity hedge losses in 2013 were the result of widening transportation basis spreads, and were recovered in 2014 with the physical flow of natural gas and utilization of the contracted transportation capacity.

We account for natural gas stored in inventory differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The natural gas that we purchase and inject into storage is accounted for at the LOCOM value utilizing gas daily or spot prices at the end of the year. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period using forward natural gas prices. This difference in accounting treatment can result in volatility in wholesale services reported results, even though the expected net operating revenue and expected economic value are substantially unchanged since the date the transactions were initiated. These accounting timing differences also affect the comparability of wholesale services' period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year. Largely as a result of moderate weather in the fourth quarter of 2014 leading to significant decreases in natural gas prices, wholesale services recorded a $73 million LOCOM adjustment for the year ended December 31, 2014.

For our natural gas transportation portfolio, we enter into transportation capacity contracts with interstate and intrastate pipelines for the delivery of natural gas between receipt and delivery points in future periods. We purchase natural gas for transportation when the market price we pay for gas at a receipt point plus the cost of transportation capacity required to deliver the gas to the delivery point is less than the sales price at the delivery point. The difference between the prices at the receipt point and the delivery point is the transportation basis or location spread. Similar to our storage transactions, we attempt to mitigate the commodity price risk associated with our transportation portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas at the receipt and delivery points. We utilize futures contracts or OTC derivatives to hedge both the commodity price risk relative to the market price at the receipt point and the market price at the delivery point to substantially protect the operating revenue that we will ultimately realize once the natural gas is received, delivered and sold.

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. During both 2014 and 2013, we experienced increased price volatility brought on largely by colder weather and supply constraints in the Northeast and Midwest regions, which enabled us to capture value under these market conditions. Commercial activity in 2014 was particularly favorable due to significant natural gas price volatility as compared to prior years, largely the result of significantly colder-than-normal weather primarily in the first quarter. Prior year volatility was significantly lower due to lower daily Henry Hub spot market prices for natural gas in the U.S., robust natural gas supply, mild weather and ample storage.

While market conditions in 2014 experienced more natural gas price volatility, in the near term we anticipate low volatility in certain areas of our portfolio, but expect a continuation of some volatility in the supply-constrained Northeast corridor. Over the longer term, we expect volatility to be low to moderate and locational or transportation spreads to decrease over time as new pipelines are built to reduce the bottleneck in the currently constrained shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, our expectations are that volatility would increase. While natural gas supply increased during the 2013/2014 Heating Season in the U.S., it was not enough to meet the increased demand, resulting in the lowest storage levels in over a decade. U.S. storage levels have been restored but not to the level of previous years, which could lead to higher natural gas prices under colder-than-normal weather conditions. Additional economic factors may contribute to this environment, including the significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers and reduced levels of natural gas production. Further, if economic conditions continue to improve, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer-term basis. We continue to position Sequent's business model with respect to fixed costs and the types of contracts pursued and executed, focusing on opportunities associated with expected new builds of power generation stations, LNG exporters and natural gas utilities and producers.

Sequent's expected natural gas withdrawals from storage and expected offset to hedge losses/gains associated with Sequent's transportation portfolio at December 31, 2014 are presented in the following tables, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Sequent's expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt and delivery charges, but are net of the estimated impact of profit sharing under our asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points and forward natural gas prices at December 31, 2014. A portion of Sequent's storage inventory and transportation capacity is economically hedged with futures contracts, which results in realization of substantially fixed net operating revenues, timing notwithstanding.

	Storage withdrawal schedule		
Dollars in millions	**Total storage** (in Bcf) (WACOG $2.92)	**Expected net operating (losses) gains** (1)	**Physical transportation transactions – expected net operating losses** (2)
2015	66	$(5)	$(19)
2016 and thereafter	5	2	(19)
Total at December 31, 2014 (3)	71	$(3)	$(38)

(1) Represents expected operating gains (losses) from planned storage withdrawals associated with existing inventory positions and could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations.

(2) Represents the periods associated with the transportation derivative (gains) losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative (gains) losses recognized.

(3) Includes 5 Bcf in storage with expected operating revenues of $2 million that is currently inaccessible due to operational issues at a third-party storage facility. The owner of this facility is working to resolve these issues and the facility is expected to be operational by mid-2015. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

For the year ended December 31, 2014, we have recorded $86 million in gains associated with the hedging of our storage position, compared to $16 million in storage hedge losses in 2013. These hedge gains primarily relate to changes in natural gas prices during the fourth quarter of 2014 largely resulting from moderate weather. Sequent's storage withdrawals associated with existing inventory positions could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate.

The net operating (losses) revenues expected to be generated from the physical withdrawal of natural gas from storage do not reflect the earnings impact related to the movement in our hedges to lock in the forward location spread for the delivery of natural gas between two transportation delivery points associated with our transportation capacity portfolio.

For the year ended December 31, 2014, we have recorded $38 million in gains associated with the hedging of our transportation portfolio as compared to hedge losses of $73 million for the same period last year. Hedge losses in 2013 primarily related to forward transportation and commodity positions for 2014 and were largely offset in 2014 when the expected economic value was realized upon the physical flow of natural gas and the utilization of the contracted transportation capacity.

For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Natural Gas Price Risk."

For a discussion of commercial activity, see Item 1, "Business" under the caption "Wholesale Services."

Midstream Operations

Our midstream operations segment's primary activity is operating non-utility storage and pipeline facilities, including the development and operation of high-deliverability underground natural gas storage and pipeline assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, certain of our storage services are covered under short-, medium- and long-term contracts at fixed market rates. Based on an engineering study and mechanical integrity tests performed in 2014, we identified a lower amount of working gas capacity, further resulting in the true-up of retained fuel at one of our storage facilities, negatively impacting EBIT by $10 million for the year ended December 31, 2014. The decrease in working gas capacity is a result of naturally occurring shrinkage of the storage cavern, and we are developing strategies to recover the decreased working capacity.

In millions	**2014**	**2013**
EBIT - prior year	**$(10)**	**$10**
Operating margin		
Decrease at Jefferson Island and Central Valley primarily due to lower subscription rates, as well as hedge gains at Central Valley in 2012 that did not occur in 2013	(6)	(5)
Decrease at one of our storage facilities related to true-up of retained fuel, partially offset by higher interruptible operating margins largely at Golden Triangle in 2014 due to optimizing the facilities during the significantly colder weather in 2014	(4)	-
Decrease in operating margin	**(10)**	**(5)**
Operating expenses		
Increased maintenance, outside service costs, depreciation expense and other	4	-
Increase from Central Valley Storage and Cavern 2 at Golden Triangle both beginning commercial service during 2012, and entry into the LNG markets	-	8
Increase in operating expenses	**4**	**8**
Increase (decrease) in other income, primarily related to the impairment loss at Sawgrass Storage in December 2013	**7**	**(7)**
EBIT - current year	**$(17)**	**$(10)**

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs primarily related to our natural gas inventory are our most significant short-term financing requirements. The liquidity required to fund these short-term needs is primarily provided by our operating activities, and any needs not met are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas Credit Facility. For more information on the seasonality of our short-term borrowings, see "Short-term Debt" later in this section. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner.

Our financing activities, including long-term and short-term debt and equity, are subject to customary approval or review by state and federal regulatory bodies, including the various commissions of the states in which we conduct business. Certain financing activities we undertake may also be subject to approval by state regulatory agencies. A substantial portion of our consolidated assets, earnings and cash flows is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. Nicor Gas is restricted by regulation in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates.

We believe the amounts available to us under our long-term debt and credit facilities, as well as through the issuance of debt and equity securities combined with cash provided by operating activities will continue to allow us to meet our needs for working capital, pension and retiree welfare benefits, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years. However, considering our January 2015 maturity of $200 million of senior notes that were repaid with commercial paper, our higher expected capital expenditures related to utility rate base and infrastructure investment and our recently announced pipeline projects, we anticipate issuing additional long-term debt as our financing needs and market conditions warrant.

Our ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors include, among others, regulatory changes, the price of and demand for natural gas, and operational risks.

Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of debt and equity securities. This strategy includes active management of the percentage of total debt relative to total capitalization, as well as the term and interest rate profile of our debt securities and maintenance of an appropriate mix of debt with fixed and floating interest rates. Our variable debt target is 20% to 45% of total debt. As of December 31, 2014, our variable-rate debt was $1.5 billion, or 31%, of our total debt, compared to $1.4 billion, or 28%, as of December 31, 2013. The increase was due to $120 million of senior notes that converted from fixed-rate to variable-rate during 2014. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

In January 2015, we executed $800 million in notional value of 10 year and 30 year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated issuances of senior notes in 2015 and 2016. These debt issuances will be used to reduce our commercial paper for the amount that was borrowed to repay our senior notes that matured in January 2015 and to fund upcoming debt maturities as well as the capital expenditures associated with increased utility investment and construction of our new pipeline projects. We have designated the forward-starting interest rate swaps, which will mature on the debt issuance dates, as cash flow hedges. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" for additional information.

Our objective continues to be maintaining our strong balance sheet and liquidity profile, solid investment grade ratings and our annual dividend growth. Additionally, we will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies, acquisitions and other factors. See Item 1A, "Risk Factors" for additional information on items that could impact our liquidity and capital resource requirements.

Short-term Debt The following table provides additional information on our short-term debt throughout the year.

In millions	**Year-end balance outstanding** (1)	**Daily average balance outstanding** (2)	**Minimum balance outstanding** (2)	**Largest balance outstanding** (2)
Commercial paper - AGL Capital	$590	$399	$-	$1,006
Commercial paper - Nicor Gas	585	279	58	614
Senior notes (3)	200	192	-	200
Total short-term debt and current portion of long-term debt	$1,375	$870	$58	$1,820

(1) As of December 31, 2014.
(2) For the twelve months ended December 31, 2014. The minimum and largest balances outstanding for each debt instrument occurred at different times during the year. Consequently, the total balances are not indicative of actual borrowings on any one day during the year.
(3) These senior notes matured in January 2015 and were repaid using commercial paper.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuations of our short-term borrowings and potential liquidity risk. The fluctuations are due to our seasonal cash requirements to fund working capital needs, in particular the purchase of natural gas inventory, margin calls and collateral posting requirements. Cash requirements generally increase between June and December as we purchase natural gas in advance of the Heating Season. The timing differences of when we pay our suppliers for natural gas purchases and when we recover our costs from our customers through their monthly bills can significantly affect our cash requirements. Our short-term debt balances are typically reduced during the Heating Season, as a significant portion of our current assets, primarily natural gas inventories, are converted into cash.

Our commercial paper borrowings are supported by the $1.3 billion AGL Credit Facility and $700 million Nicor Gas Credit Facility. The credit facilities can be drawn upon to meet working capital and other general corporate needs; however, the Nicor Gas Credit Facility can only be used for the working capital needs of Nicor Gas. The interest rates payable on borrowings under these facilities are calculated either at the alternative base rate, plus an applicable margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to AGL Capital's and Nicor Gas' current credit ratings. At December 31, 2014 and 2013, we had no outstanding borrowings under either credit facility.

The timing of natural gas withdrawals is dependent on the weather and natural gas market conditions, both of which impact the price of natural gas. Increasing natural gas commodity prices can significantly impact our commercial paper borrowings. Based upon our total debt outstanding as of December 31, 2014, and our maximum 70% debt to total capitalization allowed under our financial covenants, we could potentially borrow an additional $700 million of commercial paper under the AGL Credit Facility and an additional $100 million of commercial paper under the Nicor Gas Credit Facility. As a result, based on current natural gas prices and our expected injection plan, we believe that we have sufficient liquidity to cover our working capital needs.

The lenders under our credit facilities and lines of credit are major financial institutions with $2.2 billion of committed balances and all had investment grade credit ratings as of December 31, 2014. It is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal. Commercial paper borrowings reduce availability of these credit facilities.

Long-term Debt Our long-term debt matures more than one year from December 31, 2014 and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1989; senior notes; first mortgage bonds and gas facility revenue bonds.

Our long-term cash requirements primarily depend upon the level of capital expenditures, long-term debt maturities and decisions to refinance long-term debt. The following table summarizes our long-term debt issuances over the last three years.

	Issuance date	**Amount** *(in millions)*	**Term** *(in years)*	**Interest rate**
Gas facility revenue bonds	(1)	$200	10-20	Floating rate
Senior notes (2)	May 2013	$500	30	4.4%

(1) During the first quarter of 2013, we refinanced the gas facility revenue bonds. We had no cash receipts or payments in connection with the refinancing.
(2) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $225 million we borrowed to repay senior notes that matured on April 15, 2013.

Credit Ratings Our borrowing costs and our ability to obtain adequate and cost-effective financing are directly impacted by our credit ratings, as well as the availability of financial markets. Credit ratings are important to our counterparties when we engage in certain transactions, including OTC derivatives. It is our long-term objective to maintain or improve our credit ratings in order to manage our existing financing costs and enhance our ability to raise additional capital on favorable terms.

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. The rating agencies regularly review our performance and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. A credit rating is not a recommendation to buy, sell or hold securities and each rating should be evaluated independently of other ratings.

Factors we consider important to assessing our credit ratings include our Consolidated Statements of Financial Position, leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. As of December 31, 2014, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $38 million to continue conducting business with certain customers. The following table summarizes our credit ratings as of December 31, 2014 and reflects no change from what was reported in our 2013 Form 10-K/A.

	AGL Resources			**Nicor Gas**		
	S&P	Moody's (1)	Fitch	S&P	Moody's	Fitch
Corporate rating	BBB+	n/a	BBB+	BBB+	n/a	A
Commercial paper	A-2	P-2	F2	A-2	P-1	F1
Senior unsecured	BBB+	A3	BBB+	BBB+	A2	A+
Senior secured	n/a	n/a	n/a	A	Aa3	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

(1) Credit ratings are for AGL Capital, whose obligations are fully and unconditionally guaranteed by AGL Resources.

A downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could limit our access to the commercial paper market. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

Default Provisions As indicated below, our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment or similar actions.

- Our credit facilities contain customary events of default, including but not limited to, the failure to comply with certain affirmative and negative covenants, cross-defaults to certain other material indebtedness and a change of control.
- Our credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations, and other matters customarily restricted in such agreements.
- Our credit facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. However, we typically seek to maintain these ratios at levels between 50% and 60%, except for temporary increases related to the timing of acquisition and financing activities. The following table contains our debt-to-capitalization ratios for December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2014	2013	2014	2013
Debt-to-capitalization ratio as calculated from our Consolidated Statements of Financial Position	57%	58%	62%	54%
Adjustments (1)	(2)	(1)	-	1
Debt-to-capitalization ratio as calculated within our credit facilities	55%	57%	62%	55%

(1) As defined in credit facilities, includes standby letters of credit, performance/surety bonds and excludes accumulated OCI items related to non-cash pension adjustments, other post-retirement benefits liability adjustments and accounting adjustments for cash flow hedges.

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2014 and 2013. For more information on our default provisions, see Note 8 to our consolidated financial statements under Item 8 herein.

Cash Flows

We prepare our Consolidated Statements of Cash Flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in derivative instrument assets and liabilities, deferred income taxes, gains or losses on the sale of assets and changes in the Consolidated Statements of Financial Position for working capital from the beginning to the end of the period. The following table provides a summary of our operating, investing and financing cash flows for the last three years.

In millions	2014	2013	2012
Net cash provided by (used in) (1):			
Operating activities	$655	$971	$1,003
Investing activities	(505)	(876)	(786)
Financing activities	(224)	(121)	(155)
Net (decrease) increase in cash and cash equivalents - continuing operations	(51)	(26)	53
Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	-	9
Cash and cash equivalents (including held for sale) at beginning of period	105	131	69
Cash and cash equivalents (including held for sale) at end of period	31	105	131
Less cash and cash equivalents held for sale at end of period	-	24	23
Cash and cash equivalents (excluding held for sale) at end of period	$31	$81	$108

(1) Includes activity for discontinued operations.

Cash Flow from Operating Activities *2014 compared to 2013* Our net cash flow provided by operating activities in 2014 was $655 million, a decrease of $316 million or 33% from 2013. The decrease was primarily related to (i) income taxes, largely driven by the utilization of a prior period net operating loss that reduced the 2013 tax obligation combined with taxes paid in 2014 due to increased earnings and the repatriation of cumulative foreign earnings of Tropical Shipping, (ii) increased cash for inventory and (iii) trade payables, other than energy marketing, due to higher accrued volumes in December 2013 compared to December 2012. These decreases were partially offset by increases primarily related to (i) higher earnings year over year largely attributed to significantly colder-than-normal weather in the current year and increased price volatility that enabled us to capture value in wholesale services and (ii) net energy marketing receivables and payables, due to higher cash received in 2014 from the prior year.

2013 compared to 2012 Our net cash flow provided by operating activities in 2013 was $971 million, a decrease of $32 million or 3% from 2012. The decrease was primarily related to (i) receivables, other than energy marketing, due to colder weather in 2013, which resulted in higher volumes primarily at distribution operations and retail operations that will be collected in future periods and (ii) income taxes, from accelerated tax depreciation in 2013 than in 2012. This decrease in cash provided by operating activities was partially offset by increased cash provided by (i) lower payments for incentive compensation in 2013 as a result of reduced earnings in 2012 as compared to 2011 and (ii) trade payables, other than energy marketing, due to higher gas purchase volumes primarily at distribution operations and retail operations resulting from colder weather in 2013.

Cash Flow from Investing Activities Our net cash flow used in investing activities in 2014 decreased $371 million or 42% from 2013, primarily as a result of approximately $225 million proceeds we received from the sale of Tropical Shipping during the third quarter of 2014. The decrease was also attributed to the $122 million spending on the acquisition of approximately 500,000 service plans during the first quarter of 2013. Partially offsetting this decrease was greater spending for PP&E expenditures. Our estimated PP&E expenditures for 2015 and our actual PP&E expenditures incurred in 2014, 2013 and 2012 are quantified in the following table.

In millions	**Description**	**2015** (1)	**2014**	**2013**	**2012**
Distribution business	New construction and infrastructure improvements	$408	$475	$421	$371
Regulatory infrastructure programs (2)	Programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth	424	180	226	263
Storage, pipelines and LNG facilities	Underground natural gas storage facilities, pipeline infrastructure and LNG production and transportation	103	15	8	61
Other	Primarily includes information technology and building and leasehold improvements	130	99	76	80
Total		$1,065	$769	$731	$775

(1) Estimated PP&E expenditures.
(2) Includes Investing in Illinois at Nicor Gas, STRIDE at Atlanta Gas Light, SAVE at Virginia Natural Gas and an enhanced infrastructure program at Elizabethtown Gas.

The 2014 increase in PP&E expenditures of $38 million, or 5%, was due to increased spending of $84 million primarily related to new construction and infrastructure improvements at our utilities. This was partially offset by a $46 million net decrease in expenditures for our regulatory infrastructure programs largely due to PRP at Atlanta Gas Light, which ended in 2013, offset by increased spending on our other regulatory infrastructure programs that primarily included $57 million at Atlanta Gas Light for i-VPR, $24 million at Elizabethtown Gas for AIR and $22 million at Nicor Gas for Investing in Illinois.

Our PP&E expenditures were $731 million for the year ended December 31, 2013, compared to $775 million for the same period in 2012.The decrease of $44 million, or 6%, was primarily due to decreased spending of $49 million on our natural gas storage projects consisting of $35 million at Central Valley and $14 million at Golden Triangle. Additionally, capital expenditures decreased $35 million for strategic projects and $16 million for utility infrastructure enhancement projects at Elizabethtown Gas. These decreases were partially offset by increased expenditures of $54 million for regulatory infrastructure programs at Atlanta Gas Light and $9 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our estimated expenditures for 2015 include discretionary spending for capital projects principally within the distribution business, regulatory infrastructure programs, natural gas storage and other categories. We continuously evaluate whether or not to proceed with these projects, reviewing them in relation to various factors, including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities Our net cash flow used in financing activities in 2014 increased $103 million, or 85% from 2013 primarily as the result of our $494 million issuance of senior notes in May 2013 and recovery of working capital at wholesale services, partially offset by our $225 million repayment of senior notes in April 2013 and lower commercial paper repayments in 2014 due to higher working capital needs at distribution operations. For more information on our financing activities, see short and long-term debt within Item 7 under the caption “Liquidity and Capital Resources.”

Noncontrolling Interest We recorded cash distributions for SouthStar’s dividend distributions to Piedmont of $17 million in 2014 and 2013, and $14 million in 2012 as financing activities in our Consolidated Statements of Cash Flows. The primary reason for the increase in the distribution to Piedmont from 2012 to 2013 was increased earnings for 2012 compared to 2011 and a distribution of excess working capital from the joint venture in 2013. Additionally, we received $22.5 million from Piedmont in 2013 to maintain their 15% ownership interest after we contributed our Illinois Energy business to the SouthStar joint venture.

Dividends on Common Stock Our common stock dividend payments were $233 million in 2014, $222 million in 2013 and $203 million in 2012. The increases were generally the result of the annual dividend increase of $0.04 per share for each of the last three years. However, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011 received a pro rata dividend of $0.0989 per share for the stub period, which accrued from November 19, 2011 and totaled $7 million. The dividend payments made in February 2012 were reduced by this stub period dividend. For information about restrictions on our ability to pay dividends on our common stock, see Note 9 to our consolidated financial statements under Item 8 herein.

Shelf Registration In July 2013, we filed a shelf registration statement with the SEC, which expires in 2016. Under this shelf registration statement, debt securities will be issued by AGL Capital and related guarantees will be issued by AGL Resources under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Mellon Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series, subject to our AGL Credit Facility financial covenant related to total debt to total capitalization.

Off-balance sheet arrangements We have certain guarantees, as further described in Note 11 to our consolidated financial statements under Item 8 herein. We believe the likelihood of any such payment under these guarantees is remote. No liability has been recorded for these guarantees. We also have authorized unrecognized ratemaking amounts, primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs, which are not reflected within our Consolidated Statements of Financial Position. See Note 3 to our consolidated financial statements under Item 8 herein for additional information.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of business that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services. The following table illustrates our expected future contractual obligation payments and commitments and contingencies as of December 31, 2014.

In millions	Total	2015	2016	2017	2018	2019	2020 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$200	$545	$22	$155	$350	$2,434
Short-term debt	1,175	1,175	-	-	-	-	-
Environmental remediation liabilities (2)	414	87	93	55	47	37	95
Total	$5,295	$1,462	$638	$77	$202	$387	$2,529
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$4,303	$805	$457	$280	$234	$222	$2,305
Interest charges (5)	2,762	179	171	147	146	141	1,978
Operating leases (6)	188	33	31	24	17	18	65
Asset management agreements (7)	32	9	10	7	4	2	-
Standby letters of credit, performance/surety bonds (8)	50	49	1	-	-	-	-
Other	8	3	3	1	1	-	-
Total	$7,343	$1,078	$673	$459	$402	$383	$4,348

(1) Excludes the $75 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $5 million interest rate swaps fair value adjustment. Includes the current portion of long-term debt of $200 million, which matured in January 2015.
(2) Includes charges recoverable through base rates or rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.
(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 51 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2014, and is valued at $142 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2014 and the maturity date of the underlying debt instrument. As of December 31, 2014, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2015.
(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent’s affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Standby letters of credit and performance/surety bonds. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and the maximum potential amount of future payments that could be required of us as the guarantor. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and welfare obligations. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Pension Protection Act. We calculate any required pension contributions using the traditional unit credit cost method; however, additional voluntary contributions are periodically made. Contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. The contributions represent the portion of the welfare costs for which we are responsible under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions in all of our jurisdictions, except Illinois, have phase-ins that defer a portion of the retirement benefit expenses for retirement plans other than pensions for future recovery. We recorded a regulatory asset for these future recoveries of $122 million as of December 31, 2014 and $108 million as of December 31, 2013. In Illinois, all accrued retirement plan expenses are recovered through base rates. See Note 6 to our consolidated financial statements under Item 8 herein for additional information about our pension and welfare plans.

In both 2014 and 2013, no contributions were required to our qualified pension plans. Based on the estimated funded status of the AGL Pension plan, we do not expect any required contribution to the plan in 2015. We may, at times, elect to contribute additional amounts to the AGL Pension Plan in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Policies and Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts in our consolidated financial statements and accompanying notes. Those judgments and estimates have a significant effect on our financial statements, primarily due to the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ from those estimates. We frequently reevaluate our judgments and estimates that are based upon historical experience and various other assumptions that we believe to be reasonable under the circumstances. The following is a summary of our most critical accounting policies, which represent those that may involve a higher degree of uncertainty, judgment and complexity. Our significant accounting policies are described in Note 2 to our consolidated financial statements under Item 8 herein.

Accounting for Rate-Regulated Subsidiaries

At December 31, 2014, our regulatory assets were $714 million and regulatory liabilities were $1.7 billion. At December 31, 2013, our regulatory assets were $819 million and regulatory liabilities were $1.7 billion.

Our natural gas distribution operations and certain regulated transmission and storage operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the U.S. Accordingly, the financial results of these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject.

As a result, certain costs that would normally be expensed under GAAP are permitted to be capitalized or deferred on the balance sheet because it is probable that they can be recovered through rates. The periods in which revenues or expenses are recognized are impacted by regulation. In instances where other GAAP accounting treatment supersedes Accounting Standards Codification 980 - *Regulated Operations*, we apply the other GAAP accounting treatment. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations.

Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Assets and liabilities recognized as a result of rate regulation would be written off in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2014 would result in 5% and 15% decreases in total assets and total liabilities, respectively. For more information on our regulated assets and liabilities, see Note 2 and Note 3 to our consolidated financial statements under Item 8 herein.

Accounting for Goodwill and Long-Lived Assets, including Intangible Assets

Goodwill We do not amortize our goodwill, but test it for impairment at the reporting unit level during the fourth fiscal quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its carrying value, including goodwill. If the fair value is less than the carrying value, an impairment is indicated, and we must perform a second test to quantify the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value of the entire reporting unit determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we record an impairment charge. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant’s perspective.

Under the income approach, fair value is determined based upon the present value of estimated future cash flows discounted at an appropriate risk-free rate that takes into consideration the time value of money, inflation and the risks inherent in ownership of the business being valued. These forecasts contain a degree of uncertainty, and changes in these projected cash flows could significantly increase or decrease the estimated fair value of the reporting unit. For the regulated reporting units, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach included return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and a discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

Under the market approach, fair value is determined by applying market multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

The goodwill impairment testing develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions that are subjective in nature and inherent to a discounted cash flows calculation. We weight the results of the two valuation approaches to estimate the fair value of each reporting unit.

The significant assumptions that drive the estimated fair values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC), oil prices and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment, as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2014 indicated that the estimated fair value of all but one of our reporting units with goodwill was in excess of the carrying value by approximately 30% to over 600%, and were not at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of the storage and fuels reporting unit with $14 million of goodwill exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2023 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year of which we estimated the terminal value. In the terminal year, we assumed a long-term earnings growth rate of 2.5%, which is consistent with our 2013 annual goodwill impairment test, and we believe is appropriate given the current economic and industry-specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2013 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next nine years. Should this growth not occur, this reporting unit will likely fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2014 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods.

We will continue to monitor this reporting unit for impairment and note that continued declines in contracted capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in future failure of step one of the goodwill impairment test and may also result in a future impairment of goodwill. If subscription rates and subscribed volumes decline, the estimated future cash flows will decrease from our current estimates. As of December 31, 2014, we estimate that 11% of our future cash flows will be received over the next 10 years, an additional 24% over the following 10 years and 65% in periods thereafter over the remaining useful lives of our storage facilities.

Long-Lived Assets We depreciate or amortize our long-lived and intangible assets over their estimated useful lives. Currently, we have no significant indefinite-lived intangible assets. We assess our long-lived and intangible assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. Impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

We determined that there were no long-lived asset impairments in 2014; however, our Golden Triangle storage facility within midstream operations currently has less than a 5% cushion of its undiscounted cash flows over its book value. Accordingly, if this facility experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of these long-lived assets.

Our agreement in June 2013 to acquire customer relationship intangible assets within our retail operations segment included a provision for the seller to provide an adjustment to the $32 million purchase price for attrition that exceeds historical levels. In January 2015, we received $5 million from the seller that will be reflected as a reduction to our intangible assets on our Consolidated Statements of Financial Position in 2015 and will reduce the amortization for the same amount over the remaining useful life of 13.5 years.

Derivatives and Hedging Activities

The authoritative guidance to determine whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is voluminous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in our assessment of the likelihood of future hedged transactions or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions, and changes in hedge effectiveness may impact the accounting treatment.

The authoritative guidance related to derivatives and hedging requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the Consolidated Statements of Financial Position as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for, and is designated as, a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. We utilize market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

The authoritative accounting guidance requires that changes in the derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance allows derivative gains and losses to offset related results of the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until the hedged transaction occurs in the case of a cash flow hedge. Additionally, the guidance requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

Nicor Gas and Elizabethtown Gas utilize derivative instruments to hedge the price risk for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as accounting hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory commissions, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

We use derivative instruments primarily to reduce the impact to our results of operations due to the risk of changes in the price of natural gas. The fair value of natural gas derivative instruments used to manage our exposure to changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For the derivatives utilized in retail operations and wholesale services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in our results of operations in the period of change. Retail operations records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

Additionally, as required by the authoritative guidance, we are required to classify our derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of our derivative instruments incorporates various factors required under the guidance. These factors include:

- the credit worthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of our nonperformance risk on our liabilities.

We have recorded derivative instrument assets of $287 million at December 31, 2014 and $119 million at December 31, 2013. Additionally, we have recorded derivative liabilities of $93 million at December 31, 2014 and $80 million at December 31, 2013. We recorded gains on our Consolidated Statements of Income of $139 million in 2014 and $10 million in 2012 and losses of $97 million in 2013.

If there is a significant change in the underlying market prices or pricing assumptions we use in pricing our derivative assets or liabilities, we may experience a significant impact on our financial position, results of operations and cash flows. Our derivative and hedging activities are described in further detail in Note 2 and Note 5 to our consolidated financial statements under Item 8 and Item 1, "Business," herein.

Contingencies

Our accounting policies for contingencies cover a variety of activities that are incurred in the normal course of business and generally relate to contingencies for potentially uncollectible receivables, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future.

Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 11 to our consolidated financial statements under Item 8 herein.

Pension and Welfare Plans

Our pension and welfare plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates. We annually review the estimates and assumptions underlying our pension and welfare plan costs and liabilities and update them when appropriate. The critical actuarial assumptions used to develop the required estimates for our pension and welfare plans include the following key factors:

- assumed discount rates;
- expected return on plan assets;
- the market value of plan assets;
- assumed mortality table; and
- assumed health care costs.

The discount rate is utilized in calculating the actuarial present value of our pension and welfare obligations and our annual net pension and welfare costs. When establishing our discount rate, with the assistance of our actuaries, we consider high-grade bond indices. The single equivalent discount rate is derived by applying the appropriate spot rates based on high quality (AA or better) corporate bonds that have a yield higher than the regression mean yield curve, to the forecasted future cash flows in each year for each plan.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and welfare plans costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, it does not affect that year’s annual pension or welfare plan cost; rather, this gain or loss reduces or increases future pension or welfare plan costs.

Equity market performance and corporate bond rates have a significant effect on our reported results. For the AGL Pension Plan, market performance affects our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year smoothing weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology, which affects the expected return on plan assets component of pension expense.

In addition, differences between actuarial assumptions and actual plan experience are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation (PBO) or the MRVPA for the AGL Pension Plan. The excess, if any, is amortized over the average remaining service period of active employees.

During 2014, we recorded net periodic benefit costs of $39 million (pre-capitalization) related to our defined pension and welfare benefit plans. We estimate that in 2015, we will record net periodic pension and welfare benefit costs in the range of $45 million to $49 million (pre-capitalization), a $6 million to $10 million increase compared to 2014. In determining our estimated expenses for 2015, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans	Welfare plans
Discount rate	4.2%	4.0%
Expected return on plan assets	7.75%	7.75%

The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal and retirement rates, and longer or shorter life spans of participants. The following table illustrates the effect of changing the critical actuarial assumptions for our pension and welfare plans while holding all other assumptions constant:

Dollars in millions	Percentage-point change in assumption	Increase (decrease) in PBO / APBO	Increase (decrease) in cost
Expected long-term return on plan assets	+ / - 1%	$ - / -	$(9) / 9
Discount rate	+ / - 1%	$(175) / 196	$(14) / 14

During 2014, our actuary gathered industry specific data in order to assess the appropriateness of the mortality rates for different industries and analyzed our industry group mortality experience. Accordingly, in 2014 we changed the mortality table and mortality improvement scales for the calculation of our benefit obligations as of December 31, 2014. This increased our PBO and accumulated projected benefit obligation (APBO) by $26 million and $10 million, respectively, compared to 2013.

See Note 4 and Note 6 to our consolidated financial statements under Item 8 herein for additional information on our pension and welfare plans.

Income Taxes

The determination of our provision for income taxes requires significant judgment, the use of estimates and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We account for income taxes in accordance with authoritative guidance, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some or all of the deferred tax assets will not be realized.

Deferred tax liabilities are estimated based on the expected future tax consequences of items recognized in the financial statements. Additionally, during the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. As a result, we recognize tax liabilities based on estimates of whether additional taxes and interest will be due. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns.

With the sale of Tropical Shipping in the third quarter of 2014, we determined that the cumulative foreign earnings of that business would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash.

For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. In addition, we operate within multiple tax jurisdictions and we are subject to audits in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and, in our opinion, adequate provisions for income taxes have been made for all years reported.

We had a $20 million valuation allowance on $307 million of deferred tax assets ($218 million of long-term and $89 million of current) as of December 31, 2014, reflecting the expectation that a majority of these assets will be realized. Our gross long-term deferred tax liability totaled $1,928 million at December 31, 2014. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our taxes.

We are required to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Additionally, we recognize accrued interest related to uncertain tax positions in interest expense, and penalties in operating expense in the Consolidated Statements of Income. As of December 31, 2014, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Accounting Developments

See “Accounting Developments” in Note 2 to our consolidated financial statements under Item 8 herein.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk results from changes in the fair value of natural gas. Interest rate risk is caused by fluctuations in interest rates related to our portfolio of debt instruments and equity that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. We use derivative instruments to manage these risks. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

Our RMC is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions.

Weather and Natural Gas Price Risks

Distribution Operations Our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it has no natural gas price risk.

Nicor Gas and Elizabethtown Gas enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices for customers. These derivatives are reflected at fair value and are not designated as hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers and therefore have no direct impact on earnings. Realized and unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities until recovered from or credited to our customers.

For our Illinois weather risk associated with Nicor Gas, we have a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather. For more information, see Note 2 to the consolidated financial statements under Item 8 herein.

Retail Operations and Wholesale Services We routinely utilize various types of derivative instruments to mitigate certain natural gas price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. Retail operations and wholesale services also actively manage storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. These hedging instruments are used to substantially protect economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize our exposure to declining operating margins.

Midstream Operations We use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas, conditioning gas and additional volumes of gas used to de-water our caverns (de-water gas) during the construction or expansion of storage facilities. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. Conditioning gas is used to ready a field for use and will be sold in connection with placing the storage facility into service. De-water gas is used to remove water from the cavern in anticipation of commercial service and will be sold after completion of de-watering. We also use derivative instruments for asset optimization purposes.

Consolidated The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the 12 months ended December 31, 2014 and 2013.

	Derivative instruments average values (1) **at December 31,**	
In millions	**2014**	**2013**
Asset	$152	$107
Liability	101	49

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at December 31,	
In millions	**2014**	**2013**
Asset	$287	$119
Liability	93	80

The following table illustrates the change in the net fair value of our derivative instruments during the 12 months ended December 31, 2014, 2013 and 2012, and provides detail of the net fair value of contracts outstanding as of December 31, 2014, 2013 and 2012.

In millions	**2014**	**2013**	**2012**
Net fair value of derivative instruments outstanding at beginning of period	$(82)	$36	$31
Derivative instruments realized or otherwise settled during period	38	(62)	(61)
Change in net fair value of derivative instruments	105	(56)	66
Net fair value of derivative instruments outstanding at end of period	61	(82)	36
Netting of cash collateral	133	121	69
Cash collateral and net fair value of derivative instruments outstanding at end of period (1)	$194	$39	$105

(1) Net fair value of derivative instruments outstanding includes $3 million premium and associated intrinsic value at December 31, 2014 and 2013, and $4 million at December 31, 2012 associated with weather derivatives.

The sources of our net fair value at December 31, 2014 are as follows.

In millions	**Prices actively quoted (Level 1)** (1)	**Significant other observable inputs (Level 2)** (2)
Mature through 2015	$(28)	$65
Mature 2016 – 2017	7	18
Mature 2018 – 2019	(1)	-
Total derivative instruments (3)	$(22)	$83

(1) Valued using NYMEX futures prices.
(2) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.
(3) Excludes cash collateral amounts.

VaR Our VaR may not be comparable to that of other entities due to differences in the factors used to calculate VaR. Our VaR is determined on a 95% confidence interval and a 1-day holding period, which means that 95% of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally mitigated. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

Natural gas markets experienced unprecedented levels of high volatility and prices due to the extended extreme cold weather during the first quarter of 2014, resulting in our VaR to be at elevated levels during the quarter as compared to prior periods. We actively managed and monitored the open positions and exposures that were driving the elevated VaR levels to not only remain in compliance with established policies, but to also mitigate the operational risks of not being able to meet customer needs under these extreme conditions. As conditions moderated at the end of the quarter, our period-end VaR was consistent with historical periods. We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period, SouthStar's portfolio of positions for the 12 months ended December 31, 2014, 2013 and 2012 were less than $0.1 million and Sequent had the following VaRs.

In millions	**2014**	**2013**	**2012**
Period end	$4.7	$4.7	$1.8
12-month average	4.3	2.3	2.0
High	19.7	4.9	4.8
Low	1.8	1.2	1.1

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $1.5 billion of variable-rate debt outstanding at December 31, 2014, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $15 million on an annualized basis.

We sometimes utilize interest rate swaps to help us achieve our desired mix of variable to fixed-rate debt. Our variable-rate debt target generally ranges from 20% to 45% of total debt. We may also use forward-starting interest rate swaps and interest rate lock agreements to lock in fixed interest rates on our forecasted issuances of debt. The objective of these hedges is to offset the variability of future payments associated with the interest rate on debt instruments we expect to issue. The gain or loss on the interest rate swaps designated as cash flow hedges is generally deferred in accumulated OCI until settlement, at which point it is amortized to interest expense over the life of the related debt. For additional information, see Note 2 and Note 5 to our consolidated financial statements under Item 8 herein.

During the fourth quarter of 2014, $120 million of our senior notes converted from a fixed interest rate to a LIBOR-based variable interest rate. During the first quarter of 2015, we executed $800 million of fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated debt issuances in 2015 and 2016. We have designated the forward-starting interest rate swaps, which will be settled on the debt issuance dates, as cash flow hedges.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk, as it bills 12 certificated and active Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2014, the four largest Marketers based on customer count accounted for approximately 14% of our consolidated operating margin and 20% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light.

Our gas distribution businesses offer options to help customers manage their bills, such as energy assistance programs for low-income customers and a budget payment plan that spreads gas bills more evenly throughout the year. Customer credit risk has been substantially mitigated at Nicor Gas by the bad debt rider approved by the Illinois Commission in 2010, which provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense included in its rates for the respective year. For Virginia Natural Gas and Chattanooga Gas, we are allowed to recover the gas portion of bad debt write-offs through their gas recovery mechanisms.

Nicor Gas faces potential credit risk in connection with its natural gas sales and procurement activities to the extent a counterparty defaults on a contract to pay for or deliver at agreed-upon terms and conditions. To manage this risk, Nicor Gas maintains credit policies to determine and monitor the creditworthiness of its counterparties. In doing so, Nicor Gas seeks guarantees or collateral, in the form of cash or letters of credit, which limits its exposure to any individual counterparty and enters into netting arrangements to mitigate counterparty credit risk.

Certain of our derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral we post in the normal course of business when our financial instruments are in net liability positions. As of December 31, 2014, for agreements with such features, our distribution operations derivative instruments with liability fair values totaled $44 million, for which we had posted $20 million of collateral to our counterparties.

Retail Operations We obtain credit scores for our firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed our credit threshold. We consider potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, we also assign physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

Wholesale Services We have established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. We also utilize master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. We also use other netting agreements with certain counterparties with whom we conduct significant transactions. Master netting agreements enable us to net certain assets and liabilities by counterparty. We also net across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

Additionally, we may require counterparties to pledge additional collateral when deemed necessary. We conduct credit evaluations and obtain appropriate internal approvals for a counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have an investment grade rating, which includes a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, we require credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have investment grade ratings.

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of December 31, 2014, our top 20 counterparties represented approximately 55% of the total counterparty exposure of $665 million, excluding $6 million of customer deposits.

As of December 31, 2014, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions as of December 31.

	Gross receivables		Gross payables	
In millions	**2014**	**2013**	**2014**	**2013**
Netting agreements in place:				
Counterparty is investment grade	$482	$496	$276	$265
Counterparty is non-investment grade	4	-	7	10
Counterparty has no external rating	263	260	494	393
No netting agreements in place:				
Counterparty is investment grade	30	29	-	2
Counterparty has no external rating	-	1	-	1
Amount recorded on Consolidated Statements of Financial Position	$779	$786	$777	$671

We have certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements with our counterparties would have totaled $14 million at December 31, 2014, which would not have a material impact on our consolidated results of operations, cash flows or financial condition.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at 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. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective 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 (COSO). The Company's management is responsible for these financial statements and financial statement schedule, 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. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits 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 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 11, 2015

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our principal executive officer and principal financial officer, management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014, using the criteria described in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the “COSO Framework”).

Based on our evaluation under the COSO Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 11, 2015

/s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

/s/ Andrew W. Evans
Andrew W. Evans
Executive Vice President and Chief Financial Officer

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - ASSETS

In millions	As of December 31, 2014	2013
Current assets		
Cash and cash equivalents	$31	$81
Short-term investments	8	49
Receivables		
Energy marketing	779	786
Natural gas	391	385
Unbilled revenues	256	268
Other	150	83
Less allowance for uncollectible accounts	35	29
Total receivables, net	1,541	1,493
Inventories		
Natural gas	694	637
Other	22	21
Total inventories	716	658
Derivative instruments	245	99
Prepaid expenses	223	63
Regulatory assets	83	114
Assets held for sale	-	283
Other	43	55
Total current assets	2,890	2,895
Long-term assets and other deferred debits		
Property, plant and equipment	11,552	10,938
Less accumulated depreciation	2,462	2,295
Property, plant and equipment, net	9,090	8,643
Goodwill	1,827	1,827
Regulatory assets	631	705
Intangible assets	125	145
Long-term investments	105	113
Pension assets	97	117
Derivative instruments	42	20
Other	102	85
Total long-term assets and other deferred debits	12,019	11,655
Total assets	$14,909	$14,550

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - LIABILITIES AND EQUITY

In millions, except share amounts	**As of December 31, 2014**	**2013**
Current liabilities		
Short-term debt	$1,175	$1,171
Energy marketing trade payables	777	671
Other accounts payable – trade	312	421
Current portion of long-term debt	200	-
Customer deposits and credit balances	125	136
Regulatory liabilities	112	183
Accrued wages and salaries	97	66
Derivative instruments	88	75
Accrued environmental remediation liabilities	87	70
Accrued taxes	79	85
Accrued interest	53	52
Liabilities held for sale	-	40
Other	114	148
Total current liabilities	3,219	3,118
Long-term liabilities and other deferred credits		
Long-term debt	3,602	3,813
Accumulated deferred income taxes	1,724	1,628
Regulatory liabilities	1,601	1,518
Accrued pension and retiree welfare benefits	525	404
Accrued environmental remediation liabilities	327	377
Other	83	79
Total long-term liabilities and other deferred credits	7,862	7,819
Total liabilities and other deferred credits	11,081	10,937
Commitments, guarantees and contingencies (see Note 11)		
Equity		
Common shareholders' equity		
Common stock, $5 par value; 750,000,000 shares authorized; outstanding: 119,647,149 shares at December 31, 2014 and 118,888,876 shares at December 31, 2013	599	595
Additional paid-in capital	2,087	2,054
Retained earnings	1,312	1,063
Accumulated other comprehensive loss	(206)	(136)
Treasury shares, at cost: 216,523 shares at December 31, 2014 and 2013	(8)	(8)
Total common shareholders' equity	3,784	3,568
Noncontrolling interest	44	45
Total equity	3,828	3,613
Total liabilities and equity	$14,909	$14,550

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

In millions, except per share amounts	Years ended December 31, 2014	2013	2012
Operating revenues (includes revenue taxes of $133 for 2014, $112 for 2013 and $86 for 2012)	$5,385	$4,209	$3,562
Operating expenses			
Cost of goods sold	2,765	2,110	1,583
Operation and maintenance	939	887	816
Depreciation and amortization	380	397	394
Taxes other than income taxes	208	187	159
Nicor merger expenses	-	-	20
Total operating expenses	4,292	3,581	2,972
Gain on disposition of assets	2	11	-
Operating income	1,095	639	590
Other income, net	14	16	24
Interest expense, net	(179)	(170)	(183)
Income before income taxes	930	485	431
Income tax expense	350	177	157
Income from continuing operations	580	308	274
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income	500	313	275
Less net income attributable to the noncontrolling interest	18	18	15
Net income attributable to AGL Resources Inc.	$482	$295	$260
Amounts attributable to AGL Resources Inc.			
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Per common share information			
Basic earnings (loss) per common share			
Continuing operations	$4.73	$2.46	$2.21
Discontinued operations	(0.67)	0.04	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$4.06	$2.50	$2.22
Diluted earnings (loss) per common share			
Continuing operations	$4.71	$2.45	$2.20
Discontinued operations	(0.67)	0.04	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21
Cash dividends declared per common share	$1.96	$1.88	$1.74
Weighted average number of common shares outstanding			
Basic	118.8	117.9	117.0
Diluted	119.2	118.3	117.5

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
In millions	**2014**	**2013**	**2012**
Net income	$500	$313	$275
Other comprehensive income (loss), net of tax			
Retirement benefit plans, net of tax			
Actuarial (loss) gain arising during the period (net of income tax of $48, $46 and $16)	(71)	66	(17)
Prior service cost arising during the period (net of income tax of $1)	-	-	1
Reclassification of actuarial loss to net benefit cost (net of income tax of $6, $10 and $9)	9	15	13
Reclassification of prior service cost to net benefit cost (net of income tax of $1, $2 and $2)	(1)	(3)	(2)
Retirement benefit plans, net	(63)	78	(5)
Cash flow hedges, net of tax			
Net derivative instrument (loss) gain arising during the period (net of income tax of $2, $1 and $-)	(6)	1	(2)
Reclassification of realized derivative (gain) loss to net income (net of income tax of $2, $1 and $3)	(3)	3	6
Cash flow hedges, net	(9)	4	4
Other comprehensive income (loss), net of tax	(72)	82	(1)
Comprehensive income	428	395	274
Less comprehensive income attributable to noncontrolling interest	16	18	15
Comprehensive income attributable to AGL Resources Inc.	**$412**	**$377**	**$259**

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	AGL Resources Inc. Shareholders							
In millions, except per share amounts	Common stock Shares	Common stock Amount	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
As of December 31, 2011	**117.0**	**$586**	**$1,989**	**$933**	**$(217)**	**$(7)**	**$21**	**$3,305**
Net income	-	-	-	260	-	-	15	275
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)
Dividends on common stock ($1.74 per share)	-	-	-	(203)	-	-	-	(203)
Distributions to noncontrolling interests	-	-	-	-	-	-	(14)	(14)
Stock granted, share-based compensation, net of forfeitures	-	-	(10)	-	-	-	-	(10)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.6	3	19	-	-	(1)	-	21
Stock-based compensation expense, net of tax	-	-	8	-	-	-	-	8
As of December 31, 2012	**117.9**	**$590**	**$2,015**	**$990**	**$(218)**	**$(8)**	**$22**	**$3,391**
Net income	-	-	-	295	-	-	18	313
Other comprehensive income	-	-	-	-	82	-	-	82
Dividends on common stock ($1.88 per share)	-	-	-	(222)	-	-	-	(222)
Contribution from noncontrolling interest	-	-	-	-	-	-	22	22
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(6)	-	-	-	-	(6)
Stock issued, dividend reinvestment plan	0.3	1	10	-	-	-	-	11
Stock issued, share-based compensation, net of forfeitures	0.7	4	24	-	-	-	-	28
Stock-based compensation expense, net of tax	-	-	11	-	-	-	-	11
As of December 31, 2013	**118.9**	**$595**	**$2,054**	**$1,063**	**$(136)**	**$(8)**	**$45**	**$3,613**
Net income	-	-	-	482	-	-	18	500
Other comprehensive income	-	-	-	-	(70)	-	(2)	(72)
Dividends on common stock ($1.96 per share)	-	-	-	(233)	-	-	-	(233)
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(11)	-	-	-	-	(11)
Stock issued, dividend reinvestment plan	0.2	1	11	-	-	-	-	12
Stock issued, share-based compensation, net of forfeitures	0.5	3	19	-	-	-	-	22
Stock-based compensation expense, net of tax	-	-	14	-	-	-	-	14
As of December 31, 2014	**119.6**	**$599**	**$2,087**	**$1,312**	**$(206)**	**$(8)**	**$44**	**$3,828**

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Years ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$500	$313	$275
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	380	397	394
Deferred income taxes	201	(16)	157
Change in derivative instrument assets and liabilities	(155)	66	72
Gain on disposition of assets	(2)	(11)	-
Loss (income) from discontinued operations, net of tax	80	(5)	(1)
Changes in certain assets and liabilities			
Energy marketing receivables and trade payables, net	113	(54)	(44)
Accrued expenses	32	39	(28)
Prepaid and miscellaneous taxes	(244)	103	41
Trade payables, other than energy marketing	(81)	89	49
Accrued/deferred natural gas costs	(67)	2	37
Inventories	(58)	41	43
Receivables, other than energy marketing	(55)	(74)	12
Other, net	21	70	(18)
Net cash flow (used in) provided by operating activities of discontinued operations	(10)	11	14
Net cash flow provided by operating activities	655	971	1,003
Cash flows from investing activities			
Expenditures for property, plant and equipment	(769)	(731)	(775)
Dispositions of assets	230	12	-
Acquisitions of assets	-	(154)	-
Other, net	47	8	(6)
Net cash flow used in investing activities of discontinued operations	(13)	(11)	(5)
Net cash flow used in investing activities	(505)	(876)	(786)
Cash flows from financing activities			
Benefit, dividend reinvestment and stock purchase plan	22	33	21
Net issuances (repayments) of commercial paper	4	(206)	56
Dividends paid on common shares	(233)	(222)	(203)
Distribution to noncontrolling interest	(17)	(17)	(14)
Issuance of senior notes	-	494	-
Contribution from noncontrolling interest	-	22	-
Payment of senior notes	-	(225)	-
Proceeds from termination of interest rate swap	-	-	17
Payment of medium-term notes	-	-	(15)
Other, net	-	-	(17)
Net cash flow used in financing activities	(224)	(121)	(155)
Net (decrease) increase in cash and cash equivalents - continuing operations	(51)	(26)	53
Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	-	9
Cash and cash equivalents (including held for sale) at beginning of period	105	131	69
Cash and cash equivalents (including held for sale) at end of period	31	105	131
Less cash and cash equivalents held for sale at end of period	-	24	23
Cash and cash equivalents (excluding held for sale) at end of period	**$31**	**$81**	**$108**
Cash paid (received) during the period for			
Interest	$187	$175	$174
Income taxes	422	120	(37)
Non cash financing transaction			
Refinancing of gas facility revenue bonds	$-	$200	$-

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 - Organization and Basis of Presentation

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our,” the “company,” or “AGL Resources” mean consolidated AGL Resources Inc. and its subsidiaries.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2014 are prepared in accordance with GAAP and under the rules of the SEC. Our consolidated financial statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority owned or otherwise controlled subsidiaries and the accounts of our variable interest entity, SouthStar, for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we primarily use the equity method of accounting and our proportionate share of income or loss is recorded on the Consolidated Statements of Income. See Note 10 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts is probable under the affiliates’ rate regulation process.

In November 2014, we filed a 2013 Form 10-K/A to revise our financial statements and other affected disclosures for items related to the recognition of revenues for certain of our regulatory infrastructure programs and the amortization of our intangible assets as filed in our 2013 Form 10-K. Our prior period financial statements reflect the revised amounts reported in our 2013 Form 10-K/A.

In September 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position, and the financial results of these businesses are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in the following notes, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified into our “other” non-reportable segments. See Note 14 for additional information.

Certain amounts from prior periods have been reclassified to conform to the current-period presentation. The reclassifications had no material impact on our prior-period balances.

Note 2 - Significant Accounting Policies and Methods of Application

Cash and Cash Equivalents

Our cash and cash equivalents primarily consist of cash on deposit, money market accounts and certificates of deposit held by domestic subsidiaries with original maturities of three months or less. As of December 31, 2013, $24 million of cash and cash equivalents within our Consolidated Statements of Financial Position held by Tropical Shipping were excluded from cash and cash equivalents and included in assets held for sale. Prior to closing the sale, cash and short-term investments that were held in off-shore accounts were repatriated. See Note 12 and Note 14 for additional information on our income taxes on the cumulative foreign earnings for which no tax liability had previously been recorded.

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements that enable our wholesale services segment to net receivables and payables by counterparty upon settlement. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale services’ counterparties are settled net, they are recorded on a gross basis in our Consolidated Statements of Financial Position as energy marketing receivables and energy marketing payables.

Our wholesale services segment has trade and credit contracts that contain minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale services would need to post collateral to continue transacting business with some of its counterparties. To date, our credit ratings have exceeded the minimum requirements. As of December 31, 2014 and 2013, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status would not have had a material impact to our consolidated results of operations, cash flows or financial condition. If such collateral were not posted, wholesale services’ ability to continue transacting business with these counterparties would be negatively impacted.

Wholesale services has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is generally concentrated in 20 of its counterparties and is measured by 30-day receivable exposure plus forward exposure. We evaluate the credit risk of our counterparties using an S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being equivalent to D/Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios. As of December 31, 2014, our top 20 counterparties represented 55%, or $367 million, of our total counterparty exposure and had a weighted average S&P equivalent rating of A-.

We have established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. When wholesale services is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty combined with a reasonable measure of our credit risk. Wholesale services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Receivables and Allowance for Uncollectible Accounts

Our other trade receivables consist primarily of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and our accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience and other factors. For our remaining receivables, if we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the receivable balance to the amount we reasonably expect to collect. If circumstances change, our estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, customer deposits and general economic conditions. Customers' accounts are written off once we deem them to be uncollectible.

Nicor Gas Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year. See Note 3 for additional information on the bad debt rider.

Atlanta Gas Light Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 12 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings and collections. We obtain credit security support in an amount equal to no less than two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Inventories

For our regulated utilities, except Nicor Gas, our natural gas inventories and the inventories we hold for Marketers in Georgia are carried at cost on a WACOG basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory. Atlanta Gas Light also retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand. See Note 11 for information regarding a regulatory filing by Atlanta Gas Light related to gas inventory.

Nicor Gas' inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year end are charged to cost of goods sold at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of goods sold at the actual LIFO cost of the layers liquidated. Since the cost of gas, including inventory costs, is charged to customers without markup, subject to Illinois Commission review, LIFO liquidations have no impact on net income. At December 31, 2014, the Nicor Gas LIFO inventory balance was $141 million. Based on the average cost of gas purchased in December 2014, the estimated replacement cost of Nicor Gas' inventory at December 31, 2014 was $346 million, which exceeded the LIFO cost by $205 million. During 2014, we liquidated 6.8 Bcf of our LIFO-based inventory at an average cost per million cubic feet (Mcf) of $3.98. For gas purchased in 2014, our average cost per Mcf was $1.33 higher than the average LIFO liquidation rate. Applying LIFO cost in valuing the liquidation, as opposed to using the average gas purchase cost, had the effect of decreasing the cost of gas in 2014 by $9 million.

Our retail operations, wholesale services and midstream operations segments carry inventory at the lower of cost or market value, where cost is determined on a WACOG basis. For these segments, we evaluate the weighted average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the

WACOG are other than temporary. As indicated in the following LOCOM table, for any declines considered to be other than temporary, we record these pre-tax adjustments to our Consolidated Statements of Income to reduce the weighted average cost of the natural gas inventory to market value.

In millions	**2014**	**2013**	**2012**
Retail operations	$4	$1	$3
Wholesale services (1)	73	8	19
Midstream operations	-	-	1
Total	$77	$9	$23

(1) The increase in 2014 was due to a significant decline in natural gas prices in December 2014.

Additionally, we have $17 million of inventory at wholesale services that is currently inaccessible due to operational issues at a third-party storage facility. The owner of the storage facility is working to resolve these issues. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

At midstream operations, mechanical integrity tests and engineering studies are periodically performed on the storage facilities in accordance with certain state regulatory requirements. During 2014, an engineering study and mechanical integrity tests were performed at one of our storage facilities, identifying a lower amount of working gas capacity that is the result of naturally occurring shrinkage of the storage caverns. Further, based on the lower capacity and an analysis of the volume of natural gas stored in the facility, we recorded natural gas costs to true-up the amount of retained fuel at this facility in the amount of $10 million. Our other storage facilities at midstream operations were not impacted.

Regulated Operations

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for estimated expenditures that have not yet been incurred. Generally, regulatory assets and regulatory liabilities are amortized into our Consolidated Statements of Income over the period authorized by the regulatory commissions.

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents, and derivative assets and liabilities. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate fair value. Our nonfinancial assets and liabilities include pension and other retirement benefits. See Note 4 for additional fair value disclosures.

As defined in the authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 items consist of exchange-traded derivatives, money market funds and certain retirement plan assets.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. We obtain market price data from multiple sources in order to value some of our Level 2 transactions and this data is representative of transactions that occurred in the marketplace. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options and certain retirement plan assets.

Level 3 Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management's best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. Our Level 3 assets, liabilities and any applicable transfers are primarily related to our pension and welfare benefit plan assets as described in Note 4 and Note 6. We determine both transfers into and out of Level 3 using values at the end of the interim period in which the transfer occurred.

The authoritative guidance related to fair value measurements and disclosures also includes a two-step process to determine whether the market for a financial asset is inactive or a transaction is distressed. Currently, this authoritative guidance does not affect us, as our derivative instruments are traded in active markets.

Derivative Instruments

Our policy is to classify derivative cash flows and gains and losses within the same financial statement category as the hedged item, rather than by the nature of the instrument.

Fair Value Hierarchy Derivative assets and liabilities are classified in their entirety into the previously described fair value hierarchy levels based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The measurement of fair value incorporates various factors required under the guidance. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our own nonperformance risk on our liabilities. To mitigate the risk that a counterparty to a derivative instrument defaults on settlement or otherwise fails to perform under contractual terms, we have established procedures to monitor the creditworthiness of counterparties, seek guarantees or collateral backup in the form of cash or letters of credit and, in most instances, enter into netting arrangements. See Note 4 for additional fair value disclosures.

Netting of Cash Collateral and Derivative Assets and Liabilities under Master Netting Arrangements We maintain accounts with brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts.

We have elected to net derivative assets and liabilities under master netting arrangements on our Consolidated Statements of Financial Position. With that election, we are also required to offset cash collateral held in our broker accounts with the associated net fair value of the instruments in the accounts. See Note 4 for additional information about our cash collateral.

Natural Gas and Weather Derivative Instruments The fair value of the natural gas derivative instruments that we use to manage exposures arising from changing natural gas prices and weather risk reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative instruments. See Note 5 for additional derivative disclosures.

Distribution Operations Nicor Gas, subject to review by the Illinois Commission, and Elizabethtown Gas, in accordance with a directive from the New Jersey BPU, enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices. In accordance with regulatory requirements, any realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. As previously noted, such derivative instruments are reported at fair value each reporting period in our Consolidated Statements of Financial Position. Hedge accounting is not elected and, in accordance with accounting guidance pertaining to rate-regulated entities, unrealized changes in the fair value of these derivative instruments are deferred or accrued as regulatory assets or liabilities until the related revenue is recognized.

For our Illinois weather risk associated with Nicor Gas, we have a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois and is carried at intrinsic value. We will continue to use available methods to mitigate our exposure to weather in Illinois.

Retail Operations We have designated a portion of our derivative instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period that the underlying hedged item is recognized in earnings.

We currently have minimal hedge ineffectiveness, which occurs when the gains or losses on the hedging instrument more than offset the losses or gains on the hedged item. Any cash flow hedge ineffectiveness is recorded in our Consolidated Statements of Income in the period in which it occurs. We have not designated the remainder of our derivative instruments as hedges for accounting purposes and, accordingly, we record changes in the fair values of such instruments within cost of goods sold in our Consolidated Statements of Income in the period of change.

We also enter into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in operating revenues. Non exchange-traded options are accounted for using the intrinsic value method and do not qualify for hedge accounting designation. Changes in the intrinsic value for non exchange-traded contracts are also reflected in operating revenues in our Consolidated Statements of Income.

Wholesale Services We purchase natural gas for storage when the current market price we pay to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures and OTC contracts to sell natural gas at that future price to substantially protect the operating margin we will ultimately realize when the stored natural gas is sold. We also enter into transactions to secure transportation capacity between delivery points in order to serve our customers and various markets. We use NYMEX futures and OTC contracts to capture the price differential or spread between the locations served by the capacity in order to substantially protect the operating margin we will ultimately realize when we physically flow natural gas between delivery points. These contracts generally meet the definition of derivatives and are carried at fair value in our Consolidated Statements of Financial Position, with changes in fair value recorded in operating revenues in our Consolidated Statements of Income in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis we utilize for the derivatives used to mitigate the natural gas price risk associated with our storage and transportation portfolio. We incur monthly demand charges for the contracted storage and transportation capacity, and payments associated with asset management agreements, and we recognize these demand charges and payments in our Consolidated Statements of Income in the period they are incurred. This difference in accounting methods can result in volatility in our reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

Debt We estimate the fair value of debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we consider our currently assigned ratings for unsecured debt and the secured rating for the Nicor Gas first mortgage bonds.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2014 and 2013 is provided in the following table.

In millions	**2014**	**2013**
Transportation and distribution	$9,105	$8,371
Storage facilities	1,202	1,170
Other	919	854
Construction work in progress	326	543
Total PP&E, gross	11,552	10,938
Less accumulated depreciation	2,462	2,295
Total PP&E, net	$9,090	$8,643

Distribution Operations Our natural gas utilities' PP&E consists of property and equipment that is currently in use, being held for future use and currently under construction. We report PP&E at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs;
- AFUDC; and,
- Nicor Gas' pad gas - the portion considered to be non-recoverable is recorded as depreciable PP&E, while the portion considered to be recoverable is recorded as non-depreciable PP&E.

We recognize no gains or losses on depreciable utility property that is retired or otherwise disposed, as required under the composite depreciation method. Such gains and losses are ultimately refunded to, or recovered from, customers through future rate adjustments. Our natural gas utilities also hold property, primarily land; this is not presently used and useful in utility operations and is not included in rate base. Upon sale, any gain or loss is recognized in other income.

Retail Operations, Wholesale Services, Midstream Operations and Other PP&E includes property that is in use and under construction, and we report it at cost. We record a gain or loss within operation and maintenance expense for retired or otherwise disposed-of property. Natural gas in salt-dome storage at Jefferson Island and Golden Triangle that is retained as pad gas is classified as non-depreciable PP&E and is carried at cost. Central Valley has two types of pad gas in its depleted reservoir storage facility: The first is non-depreciable PP&E, which is carried at cost, and the second is non-recoverable, over which we have no contractual ownership.

On April 11, 2014, we entered into two arrangements associated with the Dalton Pipeline. The first was a construction and ownership agreement through which we will have a 50% undivided ownership interest in the 106 mile Dalton Pipeline that will be constructed in Georgia and serve as an extension of the Transco natural gas pipeline system into northwest Georgia. We also entered into an agreement to lease our 50% undivided ownership in the Dalton Pipeline once it is placed in service. The lease payments to be received are $26 million annually for an initial term of 25 years. The lessee will be responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff. Engineering design work has commenced and construction is expected to begin in the second quarter of 2016 with a targeted completion date in the second quarter of 2017. The capacity from this pipeline will further enhance system reliability as well as provide access to a more diverse supply of natural gas.

Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property. More information on our rates used and the rate method is provided in the following table.

	2014	2013	2012
Atlanta Gas Light (1)	2.3%	2.6%	2.6%
Chattanooga Gas (1)	2.5%	2.5%	2.5%
Elizabethtown Gas (2)	2.5%	2.4%	2.4%
Elkton Gas (2)	2.8%	2.4%	2.4%
Florida City Gas (2)	3.9%	3.8%	3.9%
Nicor Gas (2) (3)	3.1%	3.1%	4.1%
Virginia Natural Gas (1)	2.5%	2.5%	2.5%

(1) Average composite straight-line depreciation rates for depreciable property, excluding transportation equipment, which may be depreciated in excess of useful life and recovered in rates.
(2) Composite straight-line depreciation rates.
(3) In October 2013, the Illinois Commission approved a composite depreciation rate of 3.07%. The depreciation rate was effective as of August 30, 2013, the date the depreciation study was filed, and had the effect of reducing our 2014 and 2013 depreciation expense by $51 million and $19 million, respectively.

For our non-regulated segments, we compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets.

In years	Estimated useful life
Transportation equipment	5 – 10
Storage caverns	40 – 60
Other	up to 40

AFUDC and Capitalized Interest

Atlanta Gas Light, Nicor Gas, Chattanooga Gas and Elizabethtown Gas are authorized by applicable state regulatory agencies or legislatures to capitalize the cost of debt and equity funds as part of the cost of PP&E construction projects in our Consolidated Statements of Financial Position. The capital expenditures of our other three utilities do not qualify for AFUDC treatment. More information on our authorized or actual AFUDC rates is provided in the following table.

	2014	2013	2012
Atlanta Gas Light	8.10%	8.10%	8.10%
Nicor Gas (1)	0.24%	0.31%	0.36%
Chattanooga Gas	7.41%	7.41%	7.41%
Elizabethtown Gas (1)	0.44%	0.41%	0.51%
AFUDC (*in millions*) (2)	$7	$18	$8

(1) Variable rate is determined by FERC method of AFUDC accounting.
(2) Amount recorded in the Consolidated Statements of Income.

Asset Retirement Obligations

We record a liability at fair value for an asset retirement obligation (ARO) when a legal obligation to retire the asset has been incurred, with an offsetting increase to the carrying value of the related asset. Accretion of the ARO due to the passage of time is recorded as an operating expense. We have recorded an ARO of $3 million at December 31, 2014 and 2013 principally for our storage facilities. For our distribution PP&E, we cannot reasonably estimate the fair value of this obligation because we have determined that we have insufficient internal or industry information to reasonably estimate the potential settlement dates or costs.

Impairment of Assets

Our goodwill is not amortized, but is subject to an annual impairment test. Our other long-lived assets, including our finite-lived intangible assets, require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of the recoverability of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors.

Goodwill We perform an annual goodwill impairment test on our reporting units that contain goodwill during the fourth quarter of each year, or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, the income approach and the market approach, using assumptions consistent with a market participant's perspective.

Under the income approach, fair value is estimated based on the present value of estimated future cash flows discounted at an appropriate risk-free rate that takes into consideration the time value of money, inflation and the risks inherent in ownership of the business being valued. The cash flow estimates contain a degree of uncertainty, and changes in the projected cash flows could significantly increase or decrease the estimated fair value of a reporting unit. For the regulated reporting units, a fair recovery of, and return on, costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach include the return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, current and future rates charged for contracted capacity and a discount rate. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area. The estimated rates we will charge to customers for capacity in the storage caverns were based on internal and external rate forecasts.

Under the market approach, fair value is estimated by applying multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry, when available, to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

We weight the results of the two valuation approaches to estimate the fair value of each reporting unit. Our goodwill impairment testing also develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions that are subjective in nature and inherent to a discounted cash flows calculation.

The significant assumptions that drive the estimated values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC) and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment, as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2014 indicated that the estimated fair values of all but one of our reporting units with goodwill were in excess of the carrying values by approximately 30% to over 600%, and were not at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of our storage and fuels reporting unit with $14 million of goodwill, exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2023 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year off of which we estimated the terminal value. In the terminal year, we assumed a long-term earnings growth rate of 2.5%, which is consistent with our 2013 annual goodwill impairment test, and we believe is appropriate given the current economic and industry specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2013 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next nine years. Should this growth not occur, this reporting unit may fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2014 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods.

We will continue to monitor this reporting unit for impairment and note that continued declines in capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in a future impairment of goodwill. The amounts of goodwill as of December 31, 2014 and 2013 are provided below. In 2013, our goodwill increased by $51 million for an acquisition in our retail operations segment. For 2013, the goodwill at Tropical Shipping was classified as held for sale. See Note 14 for additional information.

In millions	**Distribution operations**	**Retail operations**	**Wholesale services**	**Midstream operations**	**Other**	**Consolidated**
Goodwill - December 31, 2014 and 2013	$1,640	$173	$-	$14	$-	$1,827

Long-Lived Assets We depreciate or amortize our long-lived assets and other intangible assets over their useful lives. We have no significant indefinite-lived intangible assets. These long-lived assets and other intangible assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through expected future cash flows. Impairment is indicated if the carrying amount of the long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

We determined that there were no long-lived asset impairments in 2014; however, our Golden Triangle storage facility within midstream operations currently has less than a 5% cushion of its undiscounted cash flows over its book value. Accordingly, if it experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of these long-lived assets. We will continue to monitor the storage assets in midstream operations. In 2013, we recorded an $8 million loss related to Sawgrass Storage.

Intangible Assets Our intangible assets within our retail operations segment are presented in the following table and represent the estimated fair value at the date of acquisition of the acquired intangible assets in our businesses. As indicated previously, we perform an impairment review when impairment indicators are present. If present, we first determine whether the carrying amount of the asset is recoverable through the undiscounted future cash flows expected from the asset. If the carrying amount is not recoverable, we measure the impairment loss, if any, as the amount by which the carrying amount of the asset exceeds its fair value.

In millions	**Weighted average amortization period** (in years)	**December 31, 2014** Gross	Accumulated amortization	Net	**December 31, 2013** Gross	Accumulated amortization	Net
Customer relationships	13	$130	$(42)	$88	$130	$(25)	$105
Trade names	13	45	(8)	37	45	(5)	40
Total		$175	$(50)	$125	$175	$(30)	$145

We amortize these intangible assets in a manner in which the economic benefits are consumed utilizing the undiscounted cash flows that were used in the determination of their fair values. Amortization expense was $20 million in 2014, $18 million in 2013 and $13 million in 2012. Amortization expense for the next five years is as follows:

In millions	**Amortization Expense**
2015	$17
2016	15
2017	14
2018	13
2019	11

Accounting for Retirement Benefit Plans

We recognize the funded status of our plans as an asset or a liability on our Consolidated Statements of Financial Position, measuring the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We generally recognize, as a component of OCI, the changes in funded status that occurred during the year that are not yet recognized as part of net periodic benefit cost. Because substantially all of its retirement costs are recoverable through base rates, Nicor Gas defers the change in funded status that would normally be charged or credited to comprehensive income to a regulatory asset or liability until the period in which the costs are included in base rates, in accordance with the authoritative guidance for rate-regulated entities. The assets of our retirement plans are measured at fair value within the funded status and are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement.

In determining net periodic benefit cost, the expected return on plan assets component is determined by applying our expected return on assets to a calculated asset value, rather than to the fair value of the assets as of the end of the previous fiscal year. For more information, see Note 6. In addition, we have elected to amortize gains and losses caused by actual experience that differs from our assumptions into subsequent periods. The amount to be amortized is the amount of the cumulative gain or loss as of the beginning of the year, excluding those gains and losses not yet reflected in the calculated value, that exceeds 10 percent of the greater of the benefit obligation or the calculated asset value; and the amortization period is the average remaining service period of active employees.

Taxes

Income Taxes The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal difference between net income and taxable income relates to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other temporary differences as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position.

We have current and deferred income taxes in our Consolidated Statements of Income. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense is generally equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

Accumulated Deferred Income Tax Assets and Liabilities As noted above, we report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure these deferred income tax assets and liabilities using enacted income tax rates.

With the sale of Tropical Shipping in the third quarter of 2014, we determined that the cumulative foreign earnings of that business would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash. Refer to Note 14 for additional information.

Income Tax Benefits The authoritative guidance related to income taxes requires us to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Uncertain Tax Positions We recognize accrued interest related to uncertain tax positions in interest expense and penalties in operating expense in our Consolidated Statements of Income.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. However, we do collect and remit various other taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position. In other instances, we are allowed to recover from customers other taxes that are imposed upon us. We record such taxes as operating expenses and record the corresponding customer charges as operating revenues.

Revenues

Distribution operations We record revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial and industrial end-use customer's distribution costs. Additionally, as required by the Georgia Commission, Atlanta Gas Light bills Marketers for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable (SFV) charge, which reflects the historic volumetric usage pattern for the entire residential class. Generally, this seasonal rate design results in billing the Marketers a higher capacity charge in the winter months and a lower charge in the summer months, which impacts our operating cash flows. However, this seasonal billing requirement does not impact our revenues, which are recognized on a straight-line basis, because the associated rate mechanism ensures that we ultimately collect the full annual amount of the SFV charges.

All of our utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas contain WNAs that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNAs have the effect of reducing customer bills when winter weather is colder-than-normal and increasing customer bills when weather is warmer-than-normal. In addition, the tariffs for Virginia Natural Gas, Chattanooga Gas and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage.

Revenue Taxes We charge customers for gas revenue and gas use taxes imposed on us and remit amounts owed to various governmental authorities. Our policy for gas revenue taxes is to record the amounts charged by us to customers, which for some taxes includes a small administrative fee, as operating revenues, and to record the related taxes imposed on us as operating expenses in our Consolidated Statements of Income. Our policy for gas use taxes is to exclude these taxes from revenue and expense, aside from a small administrative fee that is included in operating revenues as the tax is imposed on the customer. As a result, the amount recorded in operating revenues will exceed the amount recorded in operating expenses by the amount of administrative fees that are retained by the company. Revenue taxes included in operating expenses were $130 million in 2014, $110 million in 2013 and $85 million in 2012.

Retail operations Revenues from natural gas sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the most recent meter reading date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

We recognize revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. We recognize revenues for warranty and repair contracts on a straight-line basis over the contract term. Revenues for maintenance services are recognized at the time such services are performed.

Wholesale services Revenues from energy and risk management activities are required under authoritative guidance to be netted with the associated costs. Profits from sales between segments are eliminated and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under authoritative guidance related to derivatives and hedging are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are required to be presented net in revenue.

Midstream operations We record operating revenues for storage and transportation services in the period in which volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at fixed market-based rates. We recognize our park and loan revenues ratably over the life of the contract.

Cost of Goods Sold

Distribution operations Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, we charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. In accordance with the authoritative guidance for rate-regulated entities, we defer or accrue (that is, include as an asset or liability in the Consolidated Statements of Financial Position and exclude from, or include in, the Consolidated Statements of Income, respectively) the difference between the actual cost of goods sold and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. For more information, see Note 3.

Retail operations Our retail operations customers are charged for actual or estimated natural gas consumed. Within our cost of goods sold, we also include costs of fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and gains and losses associated with certain derivatives. Costs to service our warranty and repair contract claims and costs associated with the installation of HVAC equipment are recorded to cost of goods sold.

Operating Leases

We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with authoritative guidance related to leases. This accounting treatment does not affect the future annual operating lease cash obligations. For more information, see Note 11.

Other Income

Our other income is detailed in the following table. For more information on our equity investment income, see Note 10.

In millions	2014	2013	2012
Equity investment income	$8	$3	$13
AFUDC - equity	5	12	6
Other, net	1	1	5
Total other income	$14	$16	$24

Earnings Per Common Share

We compute basic earnings per common share attributable to AGL Resources Inc. common shareholders by dividing our net income attributable to AGL Resources Inc. by the daily weighted average number of common shares outstanding. Diluted earnings per common share attributable to AGL Resources Inc. common shareholders reflect the potential reduction in earnings per common share attributable to AGL Resources Inc. common shareholders that occurs when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options award programs. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance criteria and/or time-based criteria. The future issuance of shares underlying the outstanding stock options depends on whether the market price of the common shares underlying the options exceeds the respective exercise prices of the stock options.

The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented as if performance units currently earned under the plan ultimately vest and as if stock options currently exercisable at prices below the average market prices are exercised.

In millions (except per share amounts)	2014	2013	2012
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Denominator:			
Basic weighted average number of common shares outstanding (1)	118.8	117.9	117.0
Effect of dilutive securities	0.4	0.4	0.5
Diluted weighted average number of common shares outstanding (2)	119.2	118.3	117.5
Basic earnings per common share			
Continuing operations	$4.73	$2.46	$2.21
Discontinued operations	(0.67)	0.04	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$4.06	$2.50	$2.22
Diluted earnings per common share (2)			
Continuing operations	$4.71	$2.45	$2.20
Discontinued operations	(0.67)	0.04	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21

(1) Daily weighted average shares outstanding.
(2) There were no outstanding stock options excluded from the computation of diluted earnings per common share attributable to AGL Resources Inc. for any of the periods presented because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price.

Sale of Compass Energy

On May 1, 2013, we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers, within our wholesale services segment. We received an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain ($5 million net of tax). Under the terms of the purchase and sale agreement, we were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. The remaining $5 million of contingent cash consideration was to be received from the buyer annually over a five-year earn out period based upon the financial performance of Compass Energy. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received $4 million, resulting in the recognition of a $3 million gain. We have a five-year agreement through April 2018 to supply natural gas to our former customers. As a result of our continued involvement, the sale of Compass Energy did not meet the criteria for treatment as a discontinued operation in 2014. Under the new accounting guidance, which became effective for us on January 1, 2015, the sale of Compass Energy is not considered a strategic shift in operations and would not be reflected as a discontinued operation if we were to terminate our continued involvement in the future.

Non-Wholly Owned Entities

We hold ownership interests in a number of business ventures with varying ownership structures. We evaluate all of our partnership interests and other variable interests to determine if each entity is a variable interest entity (VIE), as defined in the authoritative accounting guidance. If a venture is a VIE for which we are the primary beneficiary, we consolidate the assets, liabilities and results of operations of the entity. We reassess our conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events under the guidance. We have concluded that the only venture that we are required to consolidate as a VIE, as we are the primary beneficiary, is SouthStar. On our Consolidated Statements of Financial Position, we recognize Piedmont's share of the non-wholly owned entity as a separate component of equity entitled "noncontrolling interest." Piedmont's share of current operations is reflected in "net income attributable to the noncontrolling interest" on our Consolidated Statements of Income. The consolidation of SouthStar has no effect on our calculation of basic or diluted earnings per common share amounts, which are based upon net income attributable to AGL Resources Inc.

For entities that are not determined to be VIEs, we evaluate whether we have control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under our control are consolidated, and entities over which we can exert significant influence, but do not control, are accounted for under the equity method of accounting. However, we also invest in partnerships and limited liability companies that maintain separate ownership accounts. All such investments are required to be accounted for under the equity method unless our interest is so minor that there is virtually no influence over operating and financial policies, as are all investments in joint ventures.

Investments accounted for under the equity method are included in long-term investments on our Consolidated Statements of Financial Position, and the equity income is recorded within other income on our Consolidated Statements of Income and was immaterial for all periods presented. For additional information, see Note 10.

Acquisitions

On January 31, 2013, our retail operations segment acquired approximately 500,000 service contracts and certain other assets from NiSource Inc. for $122 million. These service contracts provide home warranty protection solutions and energy efficiency leasing solutions to residential and small business utility customers and complement the retail business acquired in the Nicor merger. Intangible assets related to this acquisition are primarily customer relationships of $46 million and trade names of $16 million. These intangible assets are being amortized over approximately 14 years for customer relationships and 10 years for trade names. The final allocation of the purchase price to the fair value of assets acquired and liabilities assumed is presented in the following table:

In millions	
Current assets	$3
PP&E	12
Goodwill	51
Intangible assets	62
Current liabilities	(6)
Total purchase price	$122

On June 30, 2013, our retail operations segment acquired approximately 33,000 residential and commercial energy customer relationships in Illinois for $32 million. These customer relationships have been recorded as an intangible asset and are being amortized over 15 years.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our rate-regulated subsidiaries, uncollectible accounts and other allowances for contingent losses, goodwill and other intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. We evaluate our estimates on an ongoing basis and our actual results could differ from our estimates.

Accounting Developments

In April 2014, the FASB issued authoritative guidance related to reporting discontinued operations. The guidance generally raises the threshold for disposals to qualify as discontinued operations and requires new disclosures of both discontinued operations and certain other material disposals that do not meet the definition of a discontinued operation. The guidance was effective for us prospectively beginning January 1, 2015. It had no impact on our accounting for the sale of Tropical Shipping. There was no impact on January 1, 2015, nor is there any reason we would expect this guidance to have a material impact on our consolidated financial statements in the foreseeable future.

In May 2014, the FASB issued an update to authoritative guidance related to revenue from contracts with customers. The update replaces most of the existing guidance with a single set of principles for recognizing revenue from contracts with customers. The guidance will be effective for us beginning January 1, 2017. Early adoption is not permitted. The new guidance must be applied retrospectively to each prior period presented or via a cumulative effect upon the date of initial application. We have not yet determined the impact of this new guidance, nor have we selected a transition method.

In June 2014, the FASB issued an update to authoritative guidance related to accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance will be effective for us beginning January 1, 2016, and it will have no impact on our consolidated financial statements for our existing share-based plans.

Note 3 – Regulated Operations

Our regulatory assets and liabilities reflected within our Consolidated Statements of Financial Position as of December 31 are summarized in the following table.

In millions	2014	2013
Regulatory assets		
Recoverable ERC	$49	$45
Recoverable pension and retiree welfare benefit costs	12	9
Recoverable seasonal rates	10	10
Deferred natural gas costs	3	1
Other	9	49
Total regulatory assets - current	83	114
Recoverable ERC	326	433
Recoverable pension and retiree welfare benefit costs	110	99
Long-term debt fair value adjustment	74	82
Recoverable regulatory infrastructure program costs	69	55
Other	52	36
Total regulatory assets - long-term	631	705
Total regulatory assets	$714	$819
Regulatory liabilities		
Bad debt over collection	$33	$41
Accrued natural gas costs	27	92
Accumulated removal costs	25	27
Other	27	23
Total regulatory liabilities - current	112	183
Accumulated removal costs	1,520	1,445
Regulatory income tax liability	34	27
Unamortized investment tax credit	22	26
Bad debt over collection	12	17
Other	13	3
Total regulatory liabilities - long-term	1,601	1,518
Total regulatory liabilities	$1,713	$1,701

Base rates are designed to provide the opportunity to recover cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during future rate proceedings. We are not aware of evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs consistent with our historical recoveries.

In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income. Additionally, while some regulatory liabilities would be written off, others would continue to be recorded as liabilities, but not as regulatory liabilities.

Although the natural gas distribution industry is competing with alternative fuels, primarily electricity, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under the guidance remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider or proceeding. The regulatory liabilities that do not represent revenue collected from customers for expenditures that have not yet been incurred are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base used to periodically set base rates.

The majority of our regulatory assets and liabilities listed in the preceding table are included in base rates except for the regulatory infrastructure program costs, ERC, bad debt over collection, natural gas costs and energy efficiency costs, which are recovered through specific rate riders on a dollar-for-dollar basis. The rate riders that authorize the recovery of regulatory infrastructure program costs and natural gas costs include both a recovery of cost and a return on investment during the recovery period. Nicor Gas' rate riders for environmental costs and energy efficiency costs provide a return of investment and expense including short-term interest on reconciliation balances. However, there is no interest associated with the under or over collections of bad debt expense.

Nicor Gas' pension and retiree welfare benefit costs have historically been considered in rate proceedings in the same period they are accrued under GAAP. As a regulated utility, Nicor Gas expects to continue rate recovery of the eligible costs of these defined benefit retirement plans and, accordingly, associated changes in the funded status of Nicor Gas' plans have been deferred as a regulatory asset or liability until recognized in net income, instead of being recognized in OCI. The Illinois Commission presently does not allow Nicor Gas the opportunity to earn a return on its recoverable retirement benefit costs. Such costs are expected to be recovered over a period of approximately 10 years. The regulatory assets related to debt are also not included in rate base, but the costs are recovered over the term of the debt through the authorized rate of return component of base rates.

Unrecognized Ratemaking Amounts The following table illustrates our authorized ratemaking amounts that are not recognized in our Consolidated Statements of Financial Position. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs. These amounts will be recognized as revenues in our financial statements in the periods they are collected in rates from our customers.

In millions	**Atlanta Gas Light**	**Virginia Natural Gas**	**Elizabethtown Gas**	**Total**
December 31, 2014	$113	$12	$2	$127
December 31, 2013	80	12	1	93

Natural Gas Costs We charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms established by the state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. We defer or accrue the difference between the actual cost of gas and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities.

Environmental Remediation Costs We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites, substantially all of which is related to our MGP sites. The ERC assets and liabilities are associated with our distribution operations segment and remediation costs are generally recoverable from customers through rate mechanisms approved by regulators. Accordingly, both costs incurred to remediate the former MGP sites, plus the future estimated cost recorded as liabilities, net of amounts previously collected, are recognized as a regulatory asset until recovered from customers.

Our ERC liabilities are estimates of future remediation costs for investigation and cleanup of our current and former operating sites that are contaminated. These estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, on an undiscounted basis. These estimates contain various assumptions, which we refine and update on an ongoing basis. These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, legal expenses or other costs for which we may be held liable but for which we cannot reasonably estimate an amount.

Our accrued ERC are not regulatory liabilities; however, they are deferred as a corresponding regulatory asset until the costs are recovered from customers. These recoverable ERC assets are a combination of accrued ERC liabilities and recoverable cash expenditures for investigation and cleanup costs. We primarily recover these deferred costs through three rate riders that authorize dollar-for-dollar recovery. We expect to collect $49 million in revenues over the next 12 months, which is reflected as a current regulatory asset. We recovered $51 million in 2014, $24 million in 2013 and $13 million in 2012 from our ERC rate riders. The following table provides more information on the costs related to remediation of our current and former operating sites.

In millions	**# of sites**	**Probabilistic model cost estimates** (1)	**Engineering estimates** (1)	**Amount recorded**	**Expected costs over next 12 months**	**Cost recovery period**
Illinois (2)	26	$205 - $462	$30	$230	$41	As incurred
New Jersey	6	105 - 177	14	118	16	7 years
Georgia and Florida	13	40 - 81	15	56	21	5 years
North Carolina (3)	1	n/a	10	10	9	No recovery
Total	46	$350 - $720	$69	$414 (4)	$87	

(1) The year-end ERC cost estimates were completed as of November 30, 2014. The liability recorded reflects a reduction of these cost estimates for expenses incurred during December.

(2) Nicor Gas is responsible in whole or in part for 26 MGP sites, of which two sites have been remediated and their use is no longer restricted by the environmental condition of the property. Nicor Gas and Commonwealth Edison Company are parties to an agreement to cooperate in cleaning up residue at 23 of the sites listed. Nicor Gas' allocated share of cleanup costs for these sites is 52%.

(3) We have no regulatory recovery mechanism for the site in North Carolina. Therefore, there is no amount included within our regulatory assets and changes in estimated costs are recognized in income in the period of change.

(4) Decrease of $33 million from December 31, 2013 primarily relates to lower engineering cost estimates for work completed during 2014, partially offset by a scope increase required by the Georgia Environmental Protection Division for a site in Georgia and increases at three Illinois sites due to refinement of the assumptions used in the cost method.

In July 2014, we reached a $77 million insurance settlement for environmental claims relating to potential contamination at our MGP sites in New Jersey and North Carolina. The terms of the settlement required the $77 million to be paid in two installments. We received $45 million in the third quarter of 2014 and this payment was primarily recorded as a reduction to our recoverable ERC regulatory asset. The remaining $32 million is due in the third quarter of 2015. We will file for approval with the New Jersey BPU to utilize the insurance proceeds related to the New Jersey sites to reduce the ERC expenditures that otherwise would have been recovered from our customers in future periods. As such, the settlement, once approved, is expected to reduce our recoverable ERC regulatory asset and have a favorable impact on the rates for our Elizabethtown Gas customers.

Bad Debt Rider Nicor Gas' bad debt rider provides for the recovery from, or refund to, customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and a benchmark, as determined by the Illinois Commission in February 2010. The over recovery is recorded as an increase to operating expenses on our Consolidated Statements of Income and a regulatory liability on our Consolidated Statements of Financial Position until refunded to customers. In the period refunded, operating expenses are reduced and the regulatory liability is reversed. The actual bad debt experience and resulting refunds are shown in the following table.

		Actual	Total	Amount refunded in		Amount to be refunded in	
In millions	**Benchmark**	**bad debt**	**refund**	**2013**	**2014**	**2015**	**2016**
2014	$63	$35	$28	$-	$-	$16	$12
2013	63	21	42	-	25	17	-
2012	63	23	40	24	16	-	-

Accumulated Removal Costs In accordance with regulatory treatment, our depreciation rates are comprised of two cost components - historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through straight-line depreciation expense, with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs are not a generally accepted component of depreciation, but meet the requirements of authoritative guidance related to regulated operations, we have reclassified them from accumulated depreciation to the accumulated removal cost regulatory liability in our Consolidated Statements of Financial Position. In the rate setting process, the liability for these accumulated removal costs is treated as a reduction to the net rate base upon which our regulated utilities have the opportunity to earn their allowed rate of return.

Regulatory Infrastructure Programs We have infrastructure improvement programs at several of our utilities. Descriptions of these are as follows.

Nicor Gas In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average of 4.0% of base rate revenues. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we may implement rates under the program effective in March 2015.

Atlanta Gas Light Our STRIDE program is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and the Integrated Vintage Plastic Replacement Program (i-VPR).

The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. The STRIDE program requires us to file an updated ten-year forecast of infrastructure requirements under i-SRP along with a new construction plan every three years for review and approval by the Georgia Commission. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

A new $260 million, four-year STRIDE program was approved in December 2013, of which $214 million is for i-SRP related projects and $46 million is for i-CGP related projects. The program will be funded through a monthly rider surcharge per customer of $0.48 beginning in January 2015, which will increase to $0.96 beginning in January 2016 and to $1.43 beginning in January 2017. This surcharge will continue through 2025.

The purpose of the i-VPR program is to replace aging plastic pipe that was installed primarily in the 1960's to the early 1980's. We have identified approximately 3,300 miles of vintage plastic mains in our system that potentially should be considered for replacement over the next 15 - 20 years as it reaches the end of its useful life. In 2013, the Georgia Commission approved the replacement of 756 miles of vintage plastic pipe over four years at an estimated cost of $275 million. Additional reporting requirements and monitoring by the staff of the Georgia Commission were also included in the stipulation, which authorized a phased-in approach to funding the program through a monthly rider surcharge of $0.48 per customer through December 2014. This will increase to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016, which will continue through 2025.

The orders for the STRIDE programs provide for recovery of all prudent costs incurred in the performance of the program. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the programs net of any cost savings from the programs. All such amounts will be recovered through a combination of straight-fixed-variable rates and a STRIDE revenue rider surcharge. The regulatory asset represents recoverable incurred costs related to the programs that will be collected in future rates charged to customers through the rate riders. The future expected costs to be recovered through rates related to allowed, but not incurred costs, are recognized in an unrecognized ratemaking amount that is not reflected within our Consolidated Statements of Financial Position. This allowed cost consists primarily of the equity return on the capital investment under the program.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the STRIDE programs over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Elizabethtown Gas In 2009, the New Jersey BPU approved the enhanced infrastructure program for Elizabethtown Gas, which was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. In May 2011, the New Jersey BPU approved Elizabethtown Gas' request to spend an additional $40 million under this program before the end of 2012. Costs associated with the investment in this program are recovered through periodic adjustments to base rates that are approved by the New Jersey BPU. In August 2013, the New Jersey BPU approved the recovery of investments under this program through a permanent adjustment to base rates.

Additionally, in August 2013, we received approval from the New Jersey BPU for an extension of the accelerated infrastructure replacement program, which allows for infrastructure investment of $115 million over four years, effective as of September 1, 2013. Carrying charges on the additional capital expenditures will be deferred at a WACC of 6.65%, of which 4.27% will be within an unrecognized ratemaking amounts and will be recognized in future periods when recovered through rates. Unlike the previous program, there will be no adjustment to base rates for the investments under the extended program until Elizabethtown Gas files its next rate case. We agreed to file a general rate case by September 2016.

In September 2013, Elizabethtown Gas filed for a Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program designed to improve our distribution system's resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas is investing $15 million in infrastructure and related facilities and communication planning over a one year period that began in January 2014. In July 2014, the New Jersey BPU approved a modified ENDURE plan that allows for Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program.

Virginia Natural Gas In 2012, the Virginia Commission approved SAVE, an accelerated infrastructure replacement program, which is expected to be completed over a five-year period. The program permits a maximum capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering program costs through a rate rider that was effective August 1, 2012. The second year performance rate update was approved by the Virginia Commission in July 2014 and became effective as of August 2014.

Energy Smart Plan In May 2014, the Illinois Commission approved Nicor Gas' Energy Smart Plan, which outlines energy efficiency program offerings and therm reduction goals with spending of $93 million over a three-year period that began in June 2014. Nicor Gas' first energy efficiency program ended in May 2014.

Investment Tax Credits Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our Consolidated Statements of Financial Position. These investment tax credits are being amortized over the estimated lives of the related properties as credits to income tax expense.

Regulatory Income Tax Liability For our regulated utilities, we measure deferred income tax assets and liabilities using enacted income tax rates. Thus, when the statutory income tax rate declines before a temporary difference has fully reversed, the deferred income tax liability must be reduced to reflect the newly enacted income tax rates. However, the amount of the reduction is transferred to our regulatory income tax liability, which we are amortizing over the lives of the related properties as the temporary differences reverse over approximately 30 years.

Other Regulatory Assets and Liabilities Our recoverable pension and retiree welfare benefit plan costs for our utilities other than Nicor Gas are expected to be recovered through base rates over the next 2 to 21 years, based on the remaining recovery periods as designated by the applicable state regulatory commissions. This category also includes recoverable seasonal rates, which reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. These amounts are fully recoverable through base rates within one year.

Note 4 - Fair Value Measurements

Retirement benefit plans assets

The assets of the AGL Resources Inc. Retirement Plan (AGL Plan), the Employees' Retirement Plan of NUI Corporation (NUI Plan), and the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) were allocated approximately 71% equity and 29% fixed income at December 31, 2014 and 74% equity and 26% fixed income at December 31, 2013 compared to our targets of 70% to 95% equity, 5% to 20% fixed income, and up to 10% cash for both periods. The plans' investment policies provide for some variation in these targets. The actual asset allocations of our retirement plans are presented in the following table by Level within the fair value hierarchy.

	December 31, 2014									
	Pension plans (1)					Welfare plans				
In millions	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**
Cash	**$4**	**$1**	**$-**	**$5**	**1%**	**$1**	**$-**	**$-**	**$1**	**1%**
Equity securities:										
U.S. large cap (2)	$95	$203	$-	$298	33%	$-	$51	$-	$51	57%
U.S. small cap (2)	76	24	-	100	11%	-	-	-	-	-%
International companies (3)	-	123	-	123	13%	-	16	-	16	18%
Emerging markets (4)	-	31	-	31	3%	-	-	-	-	-%
Total equity securities	**$171**	**$381**	**$-**	**$552**	**60%**	**$-**	**$67**	**$-**	**$67**	**75%**
Fixed income securities:										
Corporate bonds (5)	$-	$233	$-	$233	25%	$-	$22	$-	$22	24%
Other (or gov't/muni bonds)	-	33	-	33	4%	-	-	-	-	-%
Total fixed income securities	**$-**	**$266**	**$-**	**$266**	**29%**	**$-**	**$22**	**$-**	**$22**	**24%**
Other types of investments:										
Global hedged equity (6)	$-	$-	$29	$29	3%	$-	$-	$-	$-	-%
Absolute return (7)	-	-	42	42	5%	-	-	-	-	-%
Private capital (8)	-	-	20	20	2%	-	-	-	-	-%
Total other investments	**$-**	**$-**	**$91**	**$91**	**10%**	**$-**	**$-**	**$-**	**$-**	**-%**
Total assets at fair value	**$175**	**$648**	**$91**	**$914**	**100%**	**$1**	**$89**	**$-**	**$90**	**100%**
% of fair value hierarchy	19%	71%	10%	100%		1%	99%	-%	100%	

	December 31, 2013									
	Pension plans (1)					Welfare plans				
In millions	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**% of total**
Cash	**$3**	**$1**	**$-**	**$4**	**-%**	**$1**	**$-**	**$-**	**$1**	**1%**
Equity securities:										
U.S. large cap (2)	$93	$205	$-	$298	33%	$-	$52	$-	$52	62%
U.S. small cap (2)	72	29	-	101	11%	-	-	-	-	-%
International companies (3)	-	139	-	139	15%	-	14	-	14	17%
Emerging markets (4)	-	34	-	34	4%	-	-	-	-	-%
Total equity securities	**$165**	**$407**	**$-**	**$572**	**63%**	**$-**	**$66**	**$-**	**$66**	**79%**
Fixed income securities:										
Corporate bonds (5)	$-	$207	$-	$207	23%	$-	$17	$-	$17	20%
Other (or gov't/muni bonds)	-	29	-	29	3%	-	-	-	-	-%
Total fixed income securities	**$-**	**$236**	**$-**	**$236**	**26%**	**$-**	**$17**	**$-**	**$17**	**20%**
Other types of investments:										
Global hedged equity (6)	$-	$-	$43	$43	5%	$-	$-	$-	$-	-%
Absolute return (7)	-	-	39	39	4%	-	-	-	-	-%
Private capital (8)	-	-	22	22	2%	-	-	-	-	-%
Total other investments	**$-**	**$-**	**$104**	**$104**	**11%**	**$-**	**$-**	**$-**	**$-**	**-%**
Total assets at fair value	**$168**	**$644**	**$104**	**$916**	**100%**	**$1**	**$83**	**$-**	**$84**	**100%**
% of fair value hierarchy	19%	70%	11%	100%		1%	99%	-%	100%	

(1) Includes $9 million at December 31, 2014 and December 31, 2013 of medical benefit (health and welfare) component for 401h accounts to fund a portion of the other retirement benefits.
(2) Includes funds that invest primarily in U.S. common stocks.
(3) Includes funds that invest primarily in foreign equity and equity-related securities.
(4) Includes funds that invest primarily in common stocks of emerging markets.
(5) Includes funds that invest primarily in investment grade debt and fixed income securities.
(6) Includes funds that invest in limited / general partnerships, managed accounts, and other investment entities issued by non-traditional firms or "hedge funds."
(7) Includes funds that invest primarily in investment vehicles and commodity pools as a "fund of funds."

(8) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly / indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real estate mezzanine loans.

The following is a reconciliation of our retirement plan assets in Level 3 of the fair value hierarchy.

	Fair value measurements using significant unobservable inputs - Level 3 (1)			
In millions	**Global hedged equity**	**Absolute return**	**Private capital**	**Total**
Balance at December 31, 2012	$38	$36	$23	$97
Actual return on plan assets	5	3	4	12
Sales	-	-	(5)	(5)
Balance at December 31, 2013	$43	$39	$22	$104
Actual return on plan assets	1	3	2	6
Sales	(15)	-	(4)	(19)
Balance at December 31, 2014	$29	$42	$20	$91

(1) There were no transfers out of Level 3, or between Level 1 and Level 2 for any of the periods presented.

Derivative Instruments

The following table summarizes, by level within the fair value hierarchy, our derivative assets and liabilities that were carried at fair value on a recurring basis in our Consolidated Statements of Financial Position as of December 31.

	2014		2013	
In millions	**Assets** (1)	**Liabilities**	**Assets** (1)	**Liabilities**
Natural gas derivatives				
Quoted prices in active markets (Level 1)	$58	$(80)	$6	$(79)
Significant other observable inputs (Level 2)	174	(94)	67	(79)
Netting of cash collateral	52	81	43	78
Total carrying value (2) (3)	$284	$(93)	$116	$(80)

(1) Balances of $3 million at December 31, 2014 and 2013 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.
(2) There were no significant unobservable inputs (Level 3) for any of the dates presented.
(3) There were no significant transfers between Level 1, Level 2, or Level 3 for any of the dates presented.

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which are recorded at their acquisition-date fair value. We amortize the fair value adjustment of Nicor Gas' first mortgage bonds over the lives of the bonds. The following table presents the carrying amount and fair value of our long-term debt as of December 31.

In millions	**2014**	**2013**
Long-term debt carrying amount	$3,802	$3,813
Long-term debt fair value (1)	4,231	3,956

(1) Fair value determined using Level 2 inputs.

Note 5 - Derivative Instruments

Our risk management activities are monitored by our Risk Management Committee, which consists of members of senior management and is charged with reviewing our risk management activities and enforcing policies. Our use of derivative instruments, including physical transactions, is limited to predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following types of derivative instruments and energy-related contracts to manage natural gas price, interest rate, weather, automobile fuel price and foreign currency risks when deemed appropriate:

- forward, futures and options contracts;
- financial swaps;
- treasury locks;
- weather derivative contracts;
- storage and transportation capacity contracts; and
- foreign currency forward contracts

Certain of our derivative instruments contain credit-risk-related or other contingent features that could require us to post collateral in the normal course of business when our financial instruments are in net liability positions. As of December 31, 2014 and 2013, for agreements with such features, derivative instruments with liability fair values totaled $93 million and $80 million, respectively, for which we had posted no collateral to our counterparties. The maximum collateral that could be required with these features is $14 million. For more information, see "Energy Marketing Receivables and Payables" in Note 2, which also have credit risk-related contingent features. Our derivative instrument activities are included within operating cash flows as an increase (decrease) to net income of $(155) million, $66 million and $72 million for the periods ended December 31, 2014, 2013 and 2012, respectively.

The following table summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

Accounting Treatment	Recognition and Measurement	
	Statements of Financial Position	**Income Statements**
Cash flow hedge	Derivative carried at fair value	Ineffective portion of the gain or loss realized and unrealized on the derivative instrument is recognized in earnings
	Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated OCI (loss)	Effective portion of the gain or loss realized and unrealized on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the hedged transaction affects earnings
Fair value hedge	Derivative carried at fair value	Gains or losses realized and unrealized on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings
	Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	
Not designated as hedges	Derivative carried at fair value	Gains or losses realized and unrealized on the derivative instrument are recognized in earnings
	Distribution operations' gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in cost of goods sold	Gains or losses realized and unrealized on these derivative instruments are ultimately included in billings to customers and are recognized in cost of goods sold in the same period as the related revenues

Quantitative Disclosures Related to Derivative Instruments

As of the dates presented, our derivative instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. As of December 31, we had a net long natural gas contracts position outstanding in the following quantities:

In Bcf (1)	**2014** (2)	**2013**
Cash flow hedges	9	6
Not designated as hedges	75	183
Total volumes	84	189
Short position – cash flow hedges	(4)	(6)
Short position – not designated as hedges	(2,828)	(2,616)
Long position – cash flow hedges	16	12
Long position – not designated as hedges	2,900	2,799
Net long position	84	189

(1) Volumes related to Nicor Gas exclude variable-priced contracts, which are carried at fair value, but whose fair values are not directly impacted by changes in commodity prices.
(2) Approximately 100% of these contracts have durations of two years or less and less than 1% expire between two and five years.

Derivative Instruments in our Consolidated Statements of Financial Position

In accordance with regulatory requirements, gains and losses on derivative instruments used to hedge natural gas purchases for customer use at distribution operations are reflected in accrued natural gas costs within our Consolidated Statements of Financial Position until billed to customers. The following amounts deferred as a regulatory asset or liability on our Consolidated Statements of Financial Position represent the net realized gains (losses) related to these natural gas cost hedges for the years ended December 31.

In millions	2014	2013
Nicor Gas	$10	$4
Elizabethtown Gas	2	(6)

The following table presents the fair values and Consolidated Statements of Financial Position classifications of our derivative instruments as of December 31:

		2014		2013	
In millions	**Classification**	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Designated as cash flow or fair value hedges					
Natural gas contracts	Current	$6	$(11)	$3	$(1)
Natural gas contracts	Long-term	-	(1)	-	-
Total designated as cash flow or fair value hedges		$6	$(12)	$3	$(1)
Not designated as hedges					
Natural gas contracts	Current	$1,061	$(1,020)	$691	$(761)
Natural gas contracts	Long-term	145	(119)	206	(220)
Total not designated as hedges		$1,206	$(1,139)	$897	$(981)
Gross amount of recognized assets and liabilities (1) (2)		1,212	(1,151)	900	(982)
Gross amounts offset in our Consolidated Statements of Financial Position (2)		(925)	1,058	(781)	902
Net amounts of assets and liabilities presented in our Consolidated Statements of Financial Position (3)		$287	$(93)	$119	$(80)

(1) The gross amounts of recognized assets and liabilities are netted within our Consolidated Statements of Financial Position to the extent that we have netting arrangements with the counterparties.

(2) As required by the authoritative guidance related to derivatives and hedging, the gross amounts of recognized assets and liabilities above do not include cash collateral held on deposit in broker margin accounts of $133 million as of December 31, 2014 and $121 million as of December 31, 2013. Cash collateral is included in the “Gross amounts offset in our Consolidated Statements of Financial Position” line of this table.

(3) At December 31, 2014 and 2013, we held letters of credit from counterparties that would offset, under master netting arrangements, an insignificant portion of these assets.

Derivative Instruments on the Consolidated Statements of Income

The following table presents the impacts of our derivative instruments in our Consolidated Statements of Income for the years ended December 31.

In millions	2014	2013	2012
Designated as cash flow or fair value hedges			
Natural gas contracts – net gain (loss) reclassified from OCI into cost of goods sold	$4	$(1)	$(5)
Natural gas contracts – net gain reclassified from OCI into operation and maintenance expense	1	-	-
Interest rate swaps – net loss reclassified from OCI into interest expense	-	(3)	(4)
Income tax (expense)/benefit	(2)	1	3
Total designated as cash flow or fair value hedges, net of tax	$3	$(3)	$(6)
Not designated as hedges (1)			
Natural gas contracts - net gain (loss) recorded in operating revenues	$149	$(90)	$34
Natural gas contracts - net gain (loss) recorded in cost of goods sold (2)	(7)	2	(4)
Income tax (expense)/benefit	(54)	34	(11)
Total not designated as hedges, net of tax	$88	$(54)	$19
Total gains (losses) on derivative instruments, net of tax	$91	$(57)	$13

(1) Associated with the fair value of derivative instruments held at December 31, 2014, 2013 and 2012.

(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $7 million, $5 million and $14 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Any amounts recognized in operating income related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur were immaterial for the years ended December 31, 2014, 2013 and 2012. Our expected gains to be reclassified from OCI into cost of goods sold, operation and maintenance expense, interest expense and operating revenues and recognized in our Consolidated Statements of Income over the next 12 months are $7 million. These deferred gains are related to natural gas derivative contracts associated with retail operations’ and Nicor Gas’ system use.

The expected gains are based upon the fair values of these financial instruments at December 31, 2014. The effective portion of gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in OCI during the periods is presented on our Consolidated Statements of Income. See Note 9 for these amounts.

Note 6 - Employee Benefit Plans

Investment Policies, Strategies and Oversight of Plans

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of our defined benefit retirement plans. Further, we have an Investment Policy (the Policy) for our pension and welfare benefit plans whose goal is to preserve these plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the plans' assets are managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification.

In developing our allocation policy for the pension and welfare plan assets we examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, we evaluated the risk and return tradeoffs of alternative asset classes and asset mixes given long-term historical relationships as well as prospective capital market returns. We also conducted an asset-liability study to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. We developed our asset mix guidelines by incorporating the results of these analyses with an assessment of our risk posture, and taking into account industry practices. We periodically evaluate our investment strategy to ensure that plan assets are sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, we may make changes to our targeted asset allocations and investment strategy.

Our investment strategy is designed to meet the following objectives:

- Generate investment returns that, in combination with our funding contributions, provide adequate funding to meet all current and future benefit obligations of the plans.
- Provide investment results that meet or exceed the assumed long-term rate of return, while maintaining the funded status of the plans at acceptable levels.
- Improve funded status over time.
- Decrease contribution and expense volatility as funded status improves.

To achieve these investment objectives, our investment strategy is divided into two primary portfolios of return seeking and liability hedging assets. Return seeking assets are intended to provide investment returns in excess of liability growth and reduce deficits in the funded status of the plans, while liability hedging assets are intended to reflect the sensitivity of the liabilities to changes in discount rates.

See Note 4 for a detailed listing of the investment types, amounts and percentages allocated to the plans. We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income securities (corporate and government obligations), cash and cash equivalents and other suitable investments.

Equity market performance and corporate bond rates have a significant effect on our reported funded status. Changes in the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) are mainly driven by the assumed discount rate. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is used by the AGL Plan to determine the expected return on the plan assets component of net annual pension cost. The MRVPA is a calculated value. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology.

Pension Benefits

We sponsor the AGL Plan, which is a tax-qualified defined benefit retirement plan for our eligible employees. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant, including information related to the participant's earnings history, years of service and age. In 2012, we also sponsored two other tax-qualified defined benefit retirement plans for our eligible employees, a Nicor plan and a NUI plan. Effective as of December 31, 2012, the NUI plan and the Nicor plan were merged into the AGL Plan. The participants of the former Nicor and NUI plans are now being offered their benefits, as described below, through the AGL Plan.

We generally calculate the benefits under the AGL Plan based on age, years of service and pay. The benefit formula for the AGL Plan is currently a career average earnings formula. Participants who were employees as of July 1, 2000 and who were at least 50 years of age as of that date earned benefits until December 31, 2010 under a final average pay formula. Participants who were employed as of July 1, 2000, but did not satisfy the age requirement to continue under the final average earnings formula, transitioned to the career average earnings formula on July 1, 2000.

Effective January 1, 2012, the AGL Plan was frozen with respect to participation for non-union employees hired on or after that date. Effective January 1, 2013, the AGL Plan was frozen with respect to participation for union employees hired on or after that date. Such employees are entitled to employer provided benefits under their defined contribution plan that exceed defined contribution benefits for employees who participate in the defined benefit plan.

Participants in the former Nicor plan receive noncontributory defined pension benefits. These benefits cover substantially all employees of Nicor Gas and its affiliates that adopted the Nicor plan hired prior to 1998. Pension benefits are based on years of service and the highest average annual salary for management employees and job level for collectively bargained employees (referred to as pension bands). The benefit obligation related to collectively bargained benefits reflects the most recent collective bargained agreement terms with regards to the benefit increases.

Participants in the former NUI plan included substantially all of NUI Corporation's employees who were employed on or before December 31, 2005. Florida City Gas union employees, who until February 2008 participated in a union-sponsored multiemployer plan, became eligible to participate in the AGL Plan in February 2008. The AGL Plan provides pension benefits to NUI participants based on years of credited service and final average compensation as of the plan freeze date. Effective December 31, 2005, participation and benefit accrual under the NUI Plan were frozen. As of January 1, 2006, former participants in that plan became eligible to participate in the AGL Plan.

Welfare Benefits

Until December 31, 2012, we sponsored two defined benefit retiree health care plans for our eligible employees – the AGL Welfare Plan and the Nicor Welfare Benefit Plan (Nicor Welfare Plan). Eligibility for these benefits is based on age and years of service. Effective December 31, 2012, the Nicor Welfare Plan was terminated and as of January 1, 2013, all participants under that plan became eligible to participate in the AGL Welfare Plan. This change in plan participation eligibility did not affect the benefit terms. The Nicor Welfare Plan benefits described below are now being offered to such participants under the AGL Welfare Plan. Effective March 18, 2014, the Nicor Welfare Plan was closed to participation for all Nicor employees hired on or after that date.

The AGL Welfare Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach the plan's retirement age while working for us. In addition, the AGL Welfare Plan provides life insurance for all employees if they have ten years of service at retirement. Effective March 18, 2014, the life insurance coverage is not available to new employees hired on or after that date. The state regulatory commissions have approved phase-in plans that defer a portion of the related benefits expense for future recovery. The AGL Welfare Plan terms include a limit on the employer share of costs at limits based on the coverage tier, plan elected and salary level of the employee at retirement.

Medicare eligible retirees covered by the AGL Welfare Plan, including all of those at least age 65, receive benefits through our contribution to a retiree health reimbursement arrangement account. Additionally, on the pre-65 medical coverage of the AGL Welfare Plan, our expected cost is determined by a retiree premium schedule based on salary level and years of service. Due to the cost limits, there is no impact on our periodic benefit cost or on our accumulated projected benefit obligation for a change in the assumed healthcare cost trend rate for this portion of the plan.

The plan provisions that are applicable to prior participants in the Nicor Welfare Plan include health care and life insurance benefits to eligible retired employees and include a limit on the employer share of cost for employees hired after 1982.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 provides for a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Prescription drug coverage for the Nicor Gas Medicare-eligible population changed effective January 1, 2013 from an employer-sponsored prescription drug plan with the Retiree Drug Subsidy to an Employer Group Waiver Plan (EGWP). The EGWP replaces the employer sponsored prescription drug plan.

We also have a separate unfunded supplemental retirement health care plan that provides health care and life insurance benefits to employees of discontinued businesses. This plan is noncontributory with defined benefits. Net plan expenses were immaterial in 2014 and 2013. The APBO associated with this plan was $2 million at December 31, 2014 and $2 million at December 31, 2013.

Assumptions

We considered a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We based our discount rates separately for each plan on an above-mean yield curve provided by our actuaries that is derived from a portfolio of high quality (rated AA or better) corporate bonds with a yield higher than the regression mean curve and the equivalent annuity cash flows.

The components of our pension and welfare costs are set forth in the following table.

Dollars in millions	Pension plans 2014	Pension plans 2013	Pension plans 2012	Welfare plans 2014	Welfare plans 2013	Welfare plans 2012
Service cost	$24	$29	$28	$2	$3	$4
Interest cost	47	43	44	15	14	16
Expected return on plan assets	(65)	(62)	(64)	(7)	(6)	(5)
Net amortization of prior service cost	(2)	(2)	(2)	(3)	(5)	(3)
Recognized actuarial loss	22	35	34	6	8	9
Net periodic benefit cost	$26	$43	$40	$13	$14	$21
Assumptions used to determine benefit costs						
Discount rate (1)	5.0%	4.2%	4.6%	4.7%	4.0%	4.5%
Expected return on plan assets (1)	7.8%	7.8%	8.4%	7.8%	7.8%	8.5%
Rate of compensation increase (1)	3.7%	3.7%	3.7%	3.7%	3.8%	3.8%
Pension band increase (2)	2.0%	2.0%	2.0%	n/a	n/a	n/a

(1) Rates are presented on a weighted average basis.
(2) Only applicable to the Nicor Gas union employees. The pension bands for the former Nicor Plan have been updated to reflect the new negotiated rates for 2015 and 2016, of 2.0% and 0%, respectively, as indicated in the union agreement dated March 2014.

The following tables present details about our pension and welfare plans.

Dollars in millions	Pension plans 2014	Pension plans 2013	Welfare plans 2014	Welfare plans 2013
Change in plan assets				
Fair value of plan assets, January 1,	$907	$837	$93	$77
Actual return on plan assets	68	134	5	16
Employee contributions	-	-	2	3
Employer contributions	1	1	17	19
Benefits paid	(70)	(65)	(19)	(23)
Medicare Part D reimbursements	-	-	1	1
Fair value of plan assets, December 31,	$906	$907	$99	$93
Change in benefit obligation				
Benefit obligation, January 1,	$960	$1,046	$326	$354
Service cost	24	29	2	3
Interest cost	47	43	15	14
Actuarial loss (gain)	137	(93)	8	(26)
Medicare Part D reimbursements	-	-	1	1
Benefits paid	(70)	(65)	(19)	(23)
Employee contributions	-	-	1	3
Benefit obligation, December 31,	$1,098	$960	$334	$326
Funded status at end of year	$(192)	$(53)	$(235)	$(233)
Amounts recognized in the Consolidated Statements of Financial Position consist of				
Long-term asset (2)	$97	$117	$-	$-
Current liability	(2)	(2)	-	-
Long-term liability	(287)	(168)	(235)	(233)
Net liability at December 31,	$(192)	$(53)	$(235)	$(233)
Accumulated benefit obligation (1)	$1,027	$902	n/a	n/a
Assumptions used to determine benefit obligations				
Discount rate	4.2%	5.0%	4.0%	4.7%
Rate of compensation increase	3.7%	3.7%	3.7%	3.7%
Pension band increase (3)	2.0%	2.0%	n/a	n/a

(1) APBO differs from the projected benefit obligation in that APBO excludes the effect of salary and wage increases.
(2) As a result of historically having multiple plans, a portion of our obligation is in an asset position.
(3) Only applicable to the Nicor Gas union employees.

A portion of the net benefit cost or credit related to these plans has been capitalized as a cost of constructing gas distribution facilities and the remainder is included in operation and maintenance expense.

Assumptions used to determine the health care benefit cost for the AGL Welfare Plan were as follows:

	2014	2013
Health care cost trend rate assumed for next year	8.1%	8.4%
Ultimate rate to which the cost trend rate is assumed to decline	4.5%	4.5%
Year that reaches ultimate trend rate	2030	2030

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates for the AGL Welfare Plan would have the following effects on our benefit obligation and there was no effect on our service and interest cost.

In millions	Effect on benefit obligation
1% Health care cost trend rate increase	$15
1% Health care cost trend rate decrease	(13)

As a result of a cap on expected cost for the AGL Welfare Plan, a one percentage point increase or decrease in the assumed health care trend does not materially affect the Plan's periodic benefit cost or accumulated benefit obligation.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in net regulatory assets and accumulated OCI as of December 31, 2014 and 2013:

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
December 31, 2014:						
Prior service credit	$-	$(18)	$(6)	$-	$(6)	$(18)
Net loss	76	57	307	36	383	93
Total	$76	$39	$301	$36	$377	$75
December 31, 2013:						
Prior service credit	$-	$(20)	$(9)	$-	$(9)	$(20)
Net loss	61	60	210	30	271	90
Total	$61	$40	$201	$30	$262	$70

The 2015 estimated amortizations out of regulatory assets or accumulated OCI for these plans are set forth in the following table.

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
Amortization of prior service credit	$-	$(3)	$(2)	$-	$(2)	$(3)
Amortization of net loss	9	3	20	2	29	5

We recorded regulatory assets for anticipated future cost recoveries of $122 million and $108 million as of December 31, 2014 and 2013, respectively.

The following table presents the gross benefit payments expected for the years ended December 31, 2015 through 2024 for our pension and welfare plans. There will be benefit payments under these plans beyond 2024.

In millions	Pension plans	Welfare plans
2015	$61	$19
2016	64	20
2017	67	20
2018	70	21
2019	72	22
2020-2024	374	115

Contributions

Our employees generally do not contribute to our pension and welfare plans; however, Nicor Gas and pre-65 AGL retirees make nominal contributions to their health care plan. We fund the qualified pension plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. As required by The Pension Protection Act of 2006 (the Act), we calculate the minimum amount of funding using the traditional unit credit cost method.

The Act contained new funding requirements for single-employer defined benefit pension plans and established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. In 2014 and 2013, we had no required contributions to the merged AGL Plan.

Employee Savings Plan Benefits

We sponsor defined contribution retirement benefit plans that allow eligible participants to make contributions to their accounts up to specified limits. Under these plans, our matching contributions to participant accounts were $17 million in 2014, $14 million in 2013 and $12 million in 2012.

Note 7 – Stock-Based Compensation

General

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provide for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards and other stock-based awards to officers and key employees. Under the Omnibus Performance Incentive Plan, as of December 31, 2014, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 587,292 shares. Under the Long-Term Incentive Plan (1999) as of December 31, 2014, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 436,400 shares. The maximum number of shares available for future issuance under the Omnibus Performance Incentive Plan is 3,962,335 shares, which includes 1,551,040 shares previously available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, pursuant to NYSE rules. No further grants will be made from the Long-Term Incentive Plan (1999) except for reload options that may be granted pursuant to the terms of certain outstanding options.

Accounting Treatment and Compensation Expense

We measure and recognize stock-based compensation expense for our stock-based awards over the requisite service period in our financial statements based on the estimated fair value at the date of grant for our stock-based awards using the modified prospective method. These stock awards include:

- stock options;
- stock and restricted stock awards; and
- performance units (restricted stock units, performance share units and performance cash units).

Performance-based stock awards and performance units contain market and performance conditions. Stock options, restricted stock awards and performance units also contain a service condition.

We estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates. The authoritative guidance requires excess tax benefits to be reported as a financing cash inflow. The difference between the proceeds from the exercise of our stock-based awards and the par value of the stock is recorded within additional paid-in capital.

We have granted incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. Fair market value is defined under the terms of the applicable plans as the closing price per share of AGL Resources common stock for the trading day immediately preceding the grant date, as reported in *The Wall Street Journal*. Stock options generally have a three-year vesting period.

The following table provides additional information related to our cash and stock-based compensation awards.

In millions	2014	2013	2012
Compensation costs (1)	$24	$22	$9
Income tax benefits (1)	1	1	1
Excess tax benefits (2)	-	-	1

(1) Recorded in our Consolidated Statements of Income.
(2) Recorded in our Consolidated Statements of Financial Position.

Incentive and Nonqualified Stock Options

The stock options we granted generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant.

As of December 31, 2014 and 2013, we had no unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2014 and 2013 were $9 million and $21 million, respectively, and the income tax benefit from stock option exercises was immaterial for both years. The following tables summarize activity related to stock options for key employees and non-employee directors. As used in the table, intrinsic value for options means the difference between the current market value and the grant price.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding - December 31, 2011	1,823,154	$35.61		
Granted	-	-		
Exercised	(234,844)	32.07		
Forfeited	(59,720)	37.34		
Outstanding - December 31, 2012(1)	1,528,590	$36.09		
Granted	-	-		
Exercised	(617,358)	35.37		
Forfeited	(12,500)	38.36		
Outstanding - December 31, 2013 (1)	898,732	$36.55	3.0	$10
Granted	-	-	-	
Exercised	(267,182)	36.84	1.7	
Forfeited	(4,000)	39.71	2.7	
Outstanding - December 31, 2014 (1) (2)	627,550	$36.41	2.2	$11

(1) All options outstanding at December 31, 2014, 2013 and 2012 were exercisable.
(2) The range of exercise prices for the options outstanding at December 31, 2014 was $31.09 to $43.54.

We measure compensation cost related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. There were no options granted in 2014, 2013 and 2012. We use shares purchased under our 2006 share repurchase program to satisfy exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

In general, a performance unit is an award of the right to receive (i) an equal number of shares of our common stock, which we refer to as a restricted stock unit or (ii) cash, subject to the achievement of certain pre-established performance criteria, which we refer to as a performance cash unit. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. The compensation cost of restricted stock unit awards is equal to the grant date fair value of the awards, recognized over the requisite service period, determined according to the authoritative guidance related to stock compensation. The compensation cost of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, recognized over the requisite service period. No other assumptions are used to value these awards.

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2014, we granted 44,272 restricted stock units (including dividends) to certain employees, all of which were outstanding as of December 31, 2014. These restricted stock units had a performance measurement period that ended December 31, 2014. The performance measure, which related to earnings before interest, income tax, depreciation and amortization, was met. As such, the related restricted stock awards will occur in 2015 and are subject to a three year service condition.

Performance Share Unit Awards A performance share unit award represents the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. In 2012, 2013 and 2014, we granted performance share unit awards to certain officers. These awards have a performance measure that relates to the company's relative total shareholder return relative to a group of peer companies. The recorded liability and maximum potential liability related to the 2014, 2013 and 2012 grants are as follows:

In millions	Measurement period end date	Fair value accrued at December 31, 2014	Maximum aggregate payout
Granted in 2012	December 31, 2014 (1)	$8	$20
Granted in 2013	December 31, 2015	7	21
Granted in 2014	December 31, 2016	4	24

(1) The actual liability is $8 million, and the maximum amount that could have been paid was $20 million.

Stock and Restricted Stock Awards

The compensation cost of both stock awards and restricted stock awards is equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions are used to value the awards. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Prior to vesting, restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment.

Stock Awards - ***Non-Employee Directors*** Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and non-forfeitable as of the date of grant. During 2014, we issued 21,903 shares with a weighted average fair value of $52.97 to our non-employee directors.

Restricted Stock Awards - ***Employees*** The following table summarizes the restricted stock awards activity for our employees during the last three years.

	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding - December 31, 2011 (1)	477,354		$34.40
Issued	268,840		40.08
Forfeited	(28,829)		39.07
Vested	(214,274)		36.45
Outstanding - December 31, 2012 (1)	503,091		$39.44
Issued	175,935		42.41
Forfeited	(33,352)		40.64
Vested	(204,421)		38.71
Outstanding - December 31, 2013 (1)	441,253	1.8	$40.82
Issued	262,235	4.4	47.03
Forfeited	(14,895)	2.4	43.41
Vested	(225,683)	-	42.31
Outstanding - December 31, 2014 (1)	462,910	1.8	$43.54

(1) Subject to restriction.

Employee Stock Purchase Plan (ESPP)

We have a nonqualified, broad based ESPP for all eligible employees. As of December 31, 2014, there were 422,564 shares available for future issuance under this plan. Employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value, and we record an expense for the 15% purchase price discount. Employee ESPP contributions may not exceed $25,000 per employee during any calendar year.

	2014	2013	2012
Shares purchased on the open market	100,199	97,734	103,589
Average per-share purchase price	$51.60	$42.96	$38.96
Total purchase price discount	$739,598	$628,358	$591,855

Note 8 - Debt and Credit Facilities

Our financing activities, including long-term and short-term debt, are subject to customary approval or review by state and federal regulatory bodies. Our wholly owned subsidiary, AGL Capital, was established to provide for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities and other financing arrangements. We fully and unconditionally guarantee all debt issued by AGL Capital. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize AGL Capital for its financing needs. The following table provides maturity dates, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included in our Consolidated Statements of Financial Position.

		December 31, 2014		December 31, 2013	
Dollars in millions	Year(s) due	Weighted average interest rate (1)	Outstanding	Weighted average interest rate (1)	Outstanding
Short-term debt					
Commercial paper - AGL Capital (2)	2015	0.3%	$590	0.4%	$857
Commercial paper - Nicor Gas (2)	2015	0.2	585	0.3	314
Total short-term debt		0.3%	$1,175	0.4%	$1,171
Current portion of long-term debt	2015	5.0%	$200	-%	$-
Long-term debt - excluding current portion					
Senior notes	2016-2043	5.0%	$2,625	5.0%	$2,825
First mortgage bonds	2016-2038	5.6	500	5.6	500
Gas facility revenue bonds	2022-2033	0.9	200	1.0	200
Medium-term notes	2017-2027	7.8	181	7.8	181
Total principal long-term debt		4.9%	$3,506	4.9%	$3,706
Fair value adjustment of long-term debt (3)	2016-2038	n/a	80	n/a	91
Unamortized debt premium, net	n/a	n/a	16	n/a	16
Total non-principal long-term debt		n/a	96	n/a	107
Total long-term debt			$3,602		$3,813
Total debt			$4,977		$4,984

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the 12 months ended December 31, 2014 and 2013.
(2) As of December 31, 2014, the effective interest rates on our commercial paper borrowings were 0.5% for AGL Capital and 0.4% for Nicor Gas.
(3) See Note 4 for additional information on our fair value measurements.

Short-term Debt

Our short-term debt at December 31, 2014 and 2013 was comprised of borrowings under our commercial paper programs.

Commercial Paper Programs We maintain commercial paper programs at AGL Capital and at Nicor Gas that consist of short-term, unsecured promissory notes used in conjunction with cash from operations to fund our seasonal working capital requirements. Working capital needs fluctuate during the year and are highest during the injection period in advance of the Heating Season. The Nicor Gas commercial paper program supports working capital needs at Nicor Gas, while all of our other subsidiaries and SouthStar participate in the AGL Capital commercial paper program. During 2014, our commercial paper maturities ranged from 1 to 108 days, and at December 31, 2014, remaining terms to maturity ranged from 2 to 70 days. During 2014, total borrowings and repayments netted to a borrowing of $4 million. For commercial paper issuances with original maturities over three months, borrowings and repayments were $50 million and $195 million, respectively. During 2014, we utilized a portion of the approximately $225 million in proceeds and distributions from the sale of Tropical Shipping to reduce our commercial paper borrowings.

Credit Facilities At December 31, 2014 and 2013, there were no outstanding borrowings under either the AGL Capital or Nicor Gas credit facilities. In 2013, the AGL Credit Facility and Nicor Gas Credit Facility maturity dates were extended to November 10, 2017 and December 15, 2017, respectively. The terms, conditions and pricing under the agreements remain unchanged.

Current Portion of Long-term Debt The current portion of our long-term debt at December 31, 2014 is composed of the portion of our long-term debt due within the next 12 months.

Long-term Debt

Our long-term debt at December 31, 2014 and 2013 consisted of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1, 1989; senior notes; first mortgage bonds; and gas facility revenue bonds. Some of these issuances were completed in the private placement market. In determining that those specific bonds qualify for exemption from registration under Section 4(2) of the Securities Act of 1933, we relied on the facts that the bonds were offered only to a limited number of large institutional investors and each institutional investor that purchased the bonds represented that it was purchasing the bonds for its own account and not with a view to distribute them. We fully and unconditionally guarantee all of our senior notes and gas facility revenue bonds. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds.

The majority of our long-term debt matures after fiscal year 2019. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	Amount (in millions)
2015	$200
2016	545
2017	22
2018	155
2019	350
Thereafter	2,434
Total	$3,706

Senior Notes There were no senior note issuances in 2014; however, during the fourth quarter of 2014, $120 million of senior notes that were issued to help fund the Nicor merger converted from a 1.9% fixed rate to a LIBOR-based floating rate. In 2013, we issued $500 million in 30-year senior notes with a fixed interest rate of 4.4%. The net proceeds were used to repay a portion of AGL Capital's commercial paper.

On January 23, 2015, we executed $800 million in notional value of 10 year and 30 year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated issuances of senior notes during 2015 and 2016. These debt issuances will be used to reduce our commercial paper for the amount that was borrowed to repay our senior notes that matured in January 2015 and to fund upcoming debt maturities as well as capital expenditures associated with increased utility investment and construction of our new pipeline projects. We have designated the forward-starting interest rate swaps, which will be settled on the debt issuance dates, as cash flow hedges.

First Mortgage Bonds We acquired the first mortgage bonds of Nicor Gas, which were issued through the public and private placement markets, as a result of the 2011 merger.

Gas Facility Revenue Bonds We are party to a series of loan agreements with the New Jersey Economic Development Authority and Brevard County, Florida under which a series of gas facility revenue bonds has been issued. These revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance are then loaned to us.

During 2013, we refinanced $200 million of our outstanding tax-exempt gas facility revenue bonds, which involved a combination of the issuance of $60 million of refunding bonds to, and the purchase of $140 million of existing bonds by, a syndicate of banks. We had no cash receipts or payments in connection with the refinancing. The letters of credit providing credit support for the outstanding revenue bonds along with other related agreements were terminated as a result of the refinancing.

Financial and Non-Financial Covenants

The AGL Credit Facility and the Nicor Gas Credit Facility each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month; however, our goal is to maintain these ratios at levels between 50% and 60%. These ratios, as calculated in accordance with the debt covenants, include standby letters of credit and surety bonds and exclude accumulated OCI items related to non-cash pension adjustments, welfare benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios as of December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2014	2013	2014	2013
Debt-to-capitalization ratio	55%	57%	62%	55%

The credit facilities contain certain non-financial covenants that, among other things, restrict liens and encumbrances, loans and investments, acquisitions, dividends and other restricted payments, asset dispositions, mergers and consolidations and other matters customarily restricted in such agreements.

Default Provisions

Our credit facilities and other financial obligations include provisions that, if not complied with, could require early payment or similar actions. The most important default events include the following:

- a maximum leverage ratio
- insolvency events and/or nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We have no triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other triggering events. We were in compliance with all existing debt provisions and covenants, both financial and non-financial, as of December 31, 2014 and 2013.

Note 9 - Equity

Treasury Shares

Our Board of Directors authorized us to purchase up to 8 million treasury shares through our repurchase plan, which expired on January 31, 2011. This plan was used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this plan were made in the open market or in private transactions at times and in amounts that we deemed appropriate. We held the purchased shares as treasury shares and accounted for them using the cost method. We purchased no treasury shares in 2014 or 2013.

Preferred Securities

At December 31, 2014 and 2013, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Dividends

Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors.

Additionally, we derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. As with most other companies, the payment of dividends is restricted by laws in the states where we conduct business. In certain cases, our ability to pay dividends to our common shareholders is limited by (i) our ability to pay our debts as they become due in the usual course of business and satisfy our obligations under certain financing agreements, including our debt-to-capitalization covenant, (ii) our ability to maintain total assets below total liabilities, and (iii) our ability to satisfy our obligations to any preferred shareholders.

Accumulated Other Comprehensive Loss

Our share of comprehensive income includes net income plus OCI (loss), which includes changes in fair value of certain derivatives designated as cash flow hedges, certain changes in pension and welfare benefit plans and reclassifications for amounts included in net income less net income, and OCI attributable to the noncontrolling interest. For more information on our derivative instruments, see Note 5. For more information on our pensions and retirement benefit obligations, see Note 6. Our OCI (loss) amounts are aggregated within accumulated other comprehensive loss on our Consolidated Statement of Financial Position. The following table provides changes in the components of our accumulated other comprehensive loss balances net of the related income tax effects.

In millions (1)	Cash flow hedges	Retirement benefit plans	Total
Balance as of December 31, 2011	$(7)	$(210)	$(217)
Other comprehensive income (loss)	4	(5)	(1)
Balance as of December 31, 2012	(3)	(215)	(218)
Other comprehensive income, before reclassifications	1	66	67
Amounts reclassified from accumulated other comprehensive loss	3	12	15
Balance as of December 31, 2013	1	(137)	(136)
Other comprehensive loss, before reclassifications	(6)	(71)	(77)
Amounts reclassified from accumulated other comprehensive loss	(1)	8	7
Balance as of December 31, 2014	$(6)	$(200)	$(206)

(1) All amounts are net of income taxes. Amounts in parentheses indicate debits to accumulated other comprehensive loss.

The following table provides details of the reclassifications out of accumulated other comprehensive loss for the years ended December 31, 2014 and 2013 and the ultimate unfavorable impact on net income.

	December 31,	
In millions (1)	2014	2013
Cash flow hedges		
Cost of goods sold (natural gas contracts)	$4	$(1)
Operation and maintenance expense (natural gas contracts)	1	-
Interest expense (interest rate contracts)	-	(3)
Total before income tax	5	(4)
Income tax (expense)/benefit	(2)	1
Cash flow hedges net of income tax	3	(3)
Less noncontrolling interest	2	-
Total cash flow hedges net of income tax	1	(3)
Retirement benefit plans		
Operation and maintenance expense (actuarial losses)(2)	(15)	(25)
Operation and maintenance expense (prior service credits) (2)	2	5
Total before income tax	(13)	(20)
Income tax benefit	5	8
Total retirement benefit plans	(8)	(12)
Total reclassification	$(7)	$(15)

(1) Amounts in parentheses indicate reductions to our net income and to accumulated other comprehensive loss. Except for retirement benefit plan amounts, the net income impacts are immediate.
(2) Amortization of these accumulated other comprehensive loss components is included in the computation of net periodic benefit cost. See Note 6 for additional details about net periodic benefit cost.

Note 10 - Non-Wholly Owned Entities

Variable Interest Entities

On a quarterly basis, we evaluate our variable interests in other entities, primarily ownership interests, to determine if they represent a variable interest entity (VIE) as defined by the authoritative accounting guidance on consolidation, and if so, which party is the primary beneficiary. We have determined that SouthStar, a joint venture owned by us and Piedmont, is our only VIE for which we are the primary beneficiary. This requires us to consolidate its assets, liabilities and Statements of Income. Our conclusion that SouthStar is a VIE resulted from our equal voting rights with Piedmont not being proportional to our economic obligation to absorb 85% of losses or residual returns from the joint venture. We account for our ownership of SouthStar in accordance with authoritative accounting guidance, which is described within Note 2.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to customers in Georgia, and under various other trade names to customers in Illinois, Ohio, Florida, Maryland, Michigan and New York. Following are additional factors we considered in determining that we have the power to direct SouthStar's activities that most significantly impact its performance.

Operations

Our wholly owned subsidiaries Nicor Gas and Atlanta Gas Light provide the following services, which affect SouthStar's operations:

- meter reading for SouthStar's customers in Illinois and Georgia
- maintenance and expansion of the natural gas infrastructure in Illinois and Georgia

- assignment of storage and transportation capacity used in delivering natural gas to SouthStar's customers

Liquidity and capital resources

- guarantees of SouthStar's activities with, and its credit exposure to, its counterparties and to certain natural gas suppliers in support of SouthStar's payment obligations
- support of SouthStar's daily cash management activities and assistance ensuring SouthStar has adequate liquidity and working capital resources by allowing SouthStar to utilize the AGL Capital commercial paper program for its liquidity and working capital requirements in accordance with our services agreement

Back office functions

- accounting, information technology, legal, human resources, credit and internal controls services in accordance with our services agreement

SouthStar's earnings are allocated entirely in accordance with the ownership interests and are seasonal in nature, with the majority occurring during the first and fourth quarters of each year. SouthStar's current assets consist primarily of natural gas inventory, derivative instruments and receivables from its customers. SouthStar also has receivables from us due to its participation in AGL Capital's commercial paper program. SouthStar's current liabilities consist primarily of accrued natural gas costs, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital's commercial paper program.

SouthStar's contractual commitments and obligations, including operating leases and agreements with third-party providers, do not contain terms that would trigger material financial obligations in the event that such contracts were terminated. As a result, our maximum exposure to a loss at SouthStar is considered to be immaterial. SouthStar's creditors have no recourse to our general credit beyond our corporate guarantees that we have provided to SouthStar's counterparties and natural gas suppliers. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees and the aforementioned limited protections related to goodwill and intangible assets, we have not entered into any arrangements that could require us to provide financial support to SouthStar.

Price and volume fluctuations of SouthStar's natural gas inventories can cause significant variations in our working capital and cash flow from operations. Changes in our operating cash flows are also attributable to SouthStar's working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas purchases and cash collateral amounts that SouthStar maintains to facilitate its derivative instruments.

Cash flows used in our investing activities include capital expenditures for SouthStar for the year ended December 31, of $7 million for 2014, $3 million for 2013 and $1 million for 2012. Cash flows used in our financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year. Generally, this distribution occurs in the first quarter of each fiscal year. For the years ended December 31, 2014, 2013 and 2012, SouthStar distributed $17 million, $17 million and $14 million to Piedmont, respectively.

On September 1, 2013, we contributed to SouthStar our Illinois retail energy businesses with approximately 108,000 customers. Additionally, Piedmont contributed to SouthStar $22.5 million in cash to maintain its 15% ownership in the joint venture. In connection with the contribution of our Illinois retail energy businesses, we provided certain limited protections to Piedmont regarding the value of the contributed businesses related to goodwill and other intangible assets. Piedmont's contribution is reflected as an increase to the noncontrolling interest on our Consolidated Statements of Financial Position and a financing activity on our Consolidated Statements of Cash Flows. These funds were used to reduce our commercial paper borrowings. The following table provides additional information on SouthStar's assets and liabilities as of December 31, which are consolidated within our Consolidated Statements of Financial Position.

	2014			2013		
In millions	**Consolidated**	**SouthStar** (1)	**%** (2)	**Consolidated**	**SouthStar** (1)	**%** (2)
Current assets	$2,890	$238	8%	$2,895	$264	9%
Goodwill and other intangible assets	1,952	125	6	1,972	133	7
Long-term assets and other deferred debits	10,067	17	-	9,683	13	-
Total assets	$14,909	$380	3%	$14,550	$410	3%
Current liabilities	$3,219	$71	2%	$3,118	$95	3%
Long-term liabilities and other deferred credits	7,862	-	-	7,819	-	-
Total liabilities	11,081	71	1	10,937	95	1
Equity	3,828	309	8	3,613	315	9
Total liabilities and equity	$14,909	$380	3%	$14,550	$410	3%

(1) These amounts reflect information for SouthStar and exclude intercompany eliminations and the balances of our wholly owned subsidiary with an 85% ownership interest in SouthStar.
(2) SouthStar's percentage of the amount on our Consolidated Statements of Financial Position.

The following table provides information on SouthStar's operating revenues and operating expenses for the years ended December 31, which are consolidated within our Consolidated Statements of Income.

In millions	2014	2013
Operating revenues	$866	$687
Operating expenses		
Cost of goods sold	645	491
Operation and maintenance	87	72
Depreciation and amortization	11	7
Taxes other than income taxes	1	1
Total operating expenses	744	571
Operating income	$122	$116

Equity Method Investments

Triton We have an investment in Triton, a cargo container leasing company, which is included within our "other" non-reportable segment. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement, and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2014, we had invested in seven tranches established by Triton.

Horizon Pipeline We own a 50% interest in a joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC and is included within our midstream operations segment. Horizon Pipeline operates an approximate 70-mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total capacity.

Sawgrass Storage We own a 50% interest in Sawgrass Storage, a joint venture between us and a privately held energy exploration and production company for the development of an underground natural gas storage facility in Louisiana with 30 Bcf of working gas capacity and is included within our midstream operations segment. In December 2013, the joint venture decided to terminate the development of this facility and recognized an impairment loss of $16 million, which reduced the carrying amount of the joint venture's long-lived assets to fair value. Consequently, we recognized our 50% interest in the loss during the fourth quarter of 2013, resulting in an $8 million ($5 million net of tax) charge to operating income.

The carrying amounts of our investments that are accounted for under the equity method at December 31 were as follows:

In millions	2014	2013
Triton	$62	$70
Horizon Pipeline	14	15
Other (1)	4	1
Total	$80	$86

(1) Includes our current investment in PennEast Pipeline of $1 million and Atlantic Coast pipeline of $2 million as of December 31, 2014.

Income from our equity method investments is classified as other income in our Consolidated Statements of Income. The following table provides the income from our equity method investments for the years ended December 31. The majority of our net equity investment income is attributable to our investment in Triton. For more information on our other income, see Note 2. During 2014 and 2013, we received distributions of $17 million from our equity investees.

In millions	2014	2013	2012
Triton	$6	$9	$11
Horizon Pipeline	2	2	2
Other	-	(8)	-
Total	$8	$3	$13

In 2014, we entered into two interstate pipeline joint ventures within our midstream operations segment as described below. Our investments in these joint ventures were immaterial in 2014. The capacity from these joint ventures will further enhance system reliability as well as provide access to a more diverse supply of natural gas. We have concluded that, at present, both are VIEs. We are not considered the primary beneficiary and, therefore, we have not consolidated the financial statements for these joint ventures in our consolidated financial statements because we share in the ability to direct the activities that most significantly impact their economic performance with their other member companies. We have accounted for our investment in these joint ventures using the equity method of accounting, and we have classified the investments in other noncurrent assets in our Consolidated Statements of Financial Position.

PennEast Pipeline On August 11, 2014, we entered into a joint venture in which we hold a 20% ownership interest to develop and operate a 108-mile natural gas pipeline between New Jersey and Pennsylvania with initial transportation capacity of 1 Bcf per day, which may be expanded to 1.2 Bcf per day. Subject to FERC approval, construction is expected to begin in the first quarter of 2017 with a targeted completion date in the fourth quarter of 2017.

Atlantic Coast Pipeline On September 2, 2014, we entered into a joint venture in which we hold a 5% ownership interest to develop and operate a 550-mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day, which may be expanded to 2.0 Bcf per day. Subject to FERC approval, construction is expected to begin in the second half of 2016 with a targeted completion date in the second half of 2018.

Note 11 - Commitments, Guarantees and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services, which are reflected in the table below. The following table illustrates our expected future contractual payments under our obligations and other commitments as of December 31, 2014.

In millions	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020 & thereafter**
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$200	$545	$22	$155	$350	$2,434
Short-term debt	1,175	1,175	-	-	-	-	-
Environmental remediation liabilities (2)	414	87	93	55	47	37	95
Total	$5,295	$1,462	$638	$77	$202	$387	$2,529
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$4,303	$805	$457	$280	$234	$222	$2,305
Interest charges (5)	2,762	179	171	147	146	141	1,978
Operating leases (6)	188	33	31	24	17	18	65
Asset management agreements (7)	32	9	10	7	4	2	-
Standby letters of credit, performance/surety bonds (8)	50	49	1	-	-	-	-
Other	8	3	3	1	1	-	-
Total	$7,343	$1,078	$673	$459	$402	$383	$4,348

(1) Excludes the $75 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $5 million interest rate swaps fair value adjustment. Includes our current portion of long-term debt of $200 million, which matured in January 2015.
(2) Includes charges recoverable through base rates or rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.
(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 51 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2014, and is valued at $142 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2014 and the maturity date of the underlying debt instrument. As of December 31, 2014, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2015.
(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Contingencies and Guarantees

Contingent financial commitments, such as financial guarantees, represent obligations that become payable only if certain predefined events occur. We have certain subsidiaries that enter into various financial and performance guarantees and indemnities providing assurance to third parties. We believe the likelihood of payment under our guarantees is remote. No liability has been recorded for such guarantees and indemnifications as the fair value was inconsequential at inception.

Financial guarantees AGL Equipment Leasing Inc. (AEL), a wholly owned subsidiary, holds our interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation was not impacted by the 2014 sale of Tropical Shipping and continues for the life of the Triton partnerships. Any payment is effectively limited to the net assets of AEL, which were less than $1 million at December 31, 2014. We believe the likelihood of any such payment by AEL is remote and as such no liability has been recorded for this obligation.

Indemnities In certain instances, we have undertaken to indemnify current property owners and others against costs associated with the effects and/or remediation of contaminated sites for which we may be responsible under applicable federal or state environmental laws, generally with no limitation as to the amount. These indemnifications relate primarily to ongoing coal tar cleanup, as discussed in Environmental Matters. We believe that the likelihood of payment under our other environmental indemnifications is remote. No liability has been recorded for such indemnifications as the fair value was inconsequential at inception.

Regulatory Matters

In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. In September 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several Marketers that included a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. The Georgia Commission approved the stipulation in December 2014. Over the five-year period, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, will be used to resolve 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light is obligated to resolve 25% and we have recorded a reserve in our Consolidated Statements of Financial Position representing the future estimated cost to purchase the approximately 1.15 Bcf of natural gas. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all certificated Marketers through charges for system retained storage gas as it is used by the certificated Marketers.

On August 7, 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services requesting refunds of $18 million and $22 million, respectively. We filed surrebuttal testimony in December 2014 in this proceeding disputing that any refund is due, as Nicor Gas was authorized to enter into these transactions and revenues associated with such transactions reduced rate payers' costs as either credits to the purchased gas adjustment (PGA) or reductions to base rates consistent with then-current Illinois Commission orders governing these activities. We believe these claims engage in hindsight speculation, which is expressly prohibited in a prudence review examination, and we intend to vigorously defend against these claims. Evidentiary hearings are scheduled for March 2015. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. See Note 3 for additional information.

We are involved in an investigation by the EPA regarding the applicable regulatory requirements for polychlorinated biphenyl in the Nicor Gas distribution system. While we are unable to predict the outcome of this matter or to reasonably estimate our potential exposure related thereto, if any, and have not recorded a liability associated with this contingency, the final disposition of this matter is not expected to have a material adverse impact on our liquidity or financial condition.

Litigation

We are involved in litigation arising in the normal course of business. Although in some cases we are unable to estimate the amount of loss reasonably possible in addition to any amounts already recognized, it is possible that the resolution of these contingencies, either individually or in aggregate, will require us to take charges against, or will result in reductions in, future earnings. Management believes that while the resolution of these contingencies, whether individually or in aggregate, could be material to earnings in a particular period, they will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

PBR Proceeding Nicor Gas' PBR plan was a regulatory plan that provided economic incentives based on natural gas cost performance. The PBR plan went into effect in 2000 and was terminated effective January 1, 2003, following allegations that Nicor Gas acted improperly in connection with the plan. Under this plan, Nicor Gas' total gas supply costs were compared to a market-sensitive benchmark. Savings and losses relative to the benchmark were determined annually and shared equally with sales customers. Since 2002, the amount of the savings and losses required to be shared has been disputed by the CUB and others, with the Illinois Attorney General (IAG) intervening, and subject to extensive contested discovery and other regulatory proceedings before administrative law judges and the Illinois Commission. In 2009, the staff of the Illinois Commission, IAG and CUB requested refunds of $85 million, $255 million and $305 million, respectively.

In February 2012, we committed to a stipulation with the staff of the Illinois Commission for a resolution of the dispute through credits to Nicor Gas customers of $64 million. On November 5, 2012, the Administrative Law Judges issued a proposed order for a refund of $72 million to ratepayers. In the fourth quarter of 2012, we increased our accrual for this dispute by $8 million for a total of $72 million as a result of these developments and their effect on the estimated liability.

On June 7, 2013, the Illinois Commission issued an order requiring us to refund $72 million to current Nicor Gas customers through our PGA mechanism based upon natural gas throughput over 12 months beginning on July 1, 2013. Approximately $43 million was refunded during the first half of 2014, which resulted in the completion of all refunds. On February 28, 2014, the CUB appealed the Illinois Commission's order requesting refunds consistent with its 2009 request to the appellate court in Illinois and Nicor Gas filed its response brief on July 25, 2014. The CUB filed its reply brief on October 17, 2014. There is no set time frame for a final ruling by the appellate court.

Other In addition to the matters set forth above, we are involved with legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. We are unable to determine the ultimate outcome of these other contingencies. We believe that these amounts are appropriately reflected in our consolidated financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 12 - Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors, including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense in the Consolidated Statements of Income are shown in the following table.

In millions	2014	2013	2012
Current income taxes			
Federal	$113	$164	$8
State	38	35	4
Deferred income taxes			
Federal	184	(8)	128
State	17	(11)	20
Amortization of investment tax credits	(2)	(3)	(3)
Total income tax expense	$350	$177	$157

The reconciliations between the statutory federal income tax rate of 35%, the effective rate and the related amount of income tax expense for the years ended December 31, in our Consolidated Statements of Income are presented in the following table.

In millions	2014	2013	2012
Computed tax expense at statutory rate	$325	$165	$151
State income tax, net of federal income tax benefit	36	20	19
Tax effect of net income attributable to the noncontrolling interest	(7)	(7)	(6)
Amortization of investment tax credits	(2)	(3)	(3)
Affordable housing credits	(2)	(2)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Sale of Compass Energy	-	6	-
Other	2	-	-
Total income tax expense on Consolidated Statements of Income	$350	$177	$157

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure the assets and liabilities using income tax rates that are currently in effect. The current portion of our deferred income taxes is recognized within current assets in our Consolidated Statements of Financial Position. We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net current and long-term accumulated deferred income tax liability are as follows.

	As of December 31,	
In millions	2014	2013
Current accumulated deferred income tax liabilities		
Mark-to-market	$33	$-
Inventory	26	18
Total current accumulated deferred income tax liabilities	59	18
Current accumulated deferred income tax assets		
Compensation accruals	30	19
Lower of cost or market	26	-
Allowance for doubtful accounts	12	10
Mark-to-market	-	24
Other	21	16
Total current accumulated deferred income tax assets	89	69
Valuation allowances (1)	(6)	(8)
Total current accumulated deferred income tax assets, net of valuation allowance	83	61
Net current accumulated deferred income tax asset	$24	$43

Long-term accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$1,801	$1,608
Investments in partnerships	16	18
Acquisition intangibles	14	11
Mark-to-market	12	-
Undistributed earnings of foreign subsidiaries	-	26
Other	85	97
Total long-term accumulated deferred income tax liabilities	1,928	1,760
Long-term accumulated deferred income tax assets		
Unfunded pension and retiree welfare benefit obligation	117	92
Deferred investment tax credits	6	7
Mark-to-market	-	3
Other	95	44
Total long-term accumulated deferred income tax assets	218	146
Valuation allowances (1)	(14)	(14)
Total long-term accumulated deferred income tax assets, net of valuation allowance	204	132
Net long-term accumulated deferred income tax liability	$1,724	$1,628

(1) The total valuation allowance in 2014 and 2013 is $20 million and $22 million respectively. For 2014 the total is comprised of $1 million due to net operating losses of a former non-operating facility that are not allowed in New Jersey and $19 million related to our investment in Triton. For 2013 the total is comprised of $3 million due to net operating losses in New Jersey of a former non-operating facility that are not allowed in New Jersey and $19 million related to our investment in Triton. New Jersey net operating losses expired in 2014, resulting in the reduction of the valuation allowance.

Tax Benefits

As of December 31, 2014, and December 31, 2013, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2015. As of December 31, 2014, we did not have a liability recorded for payment of interest or penalties associated with uncertain tax positions nor did we have any such interest or penalties during 2014 or 2013.

We file a U.S. federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or in any state for years before 2011.

Note 13 - Segment Information

Our reportable segments comprise revenue-generating components of our company for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance. Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. We manage our businesses through four reportable segments - distribution operations, retail operations, wholesale services, midstream operations. Our non-reportable segments are combined and presented as “other segments”.

Effective September 1, 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position, and the financial results of these businesses as of December 31, 2013 are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in this note, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified to a non-reportable segment. See Note 14 for additional information.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states. These utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Although the operations of our distribution operations segment are geographically dispersed, the operating subsidiaries within the distribution operations segment are regulated utilities, with rates determined by individual state regulatory commissions. These natural gas distribution utilities have similar economic and risk characteristics.

We are also involved in several related and complementary businesses. Our retail operations segment includes retail natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, retail operations provides home protection products and services. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, they provide natural gas asset management and/or related logistics services for each of our utilities except Nicor Gas, as well as for non-affiliated companies. Our midstream operations segment includes our non-utility storage and pipeline operations, including the operation of high-deliverability natural gas storage assets. Our “other” non-reportable segments include subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our reportable segments.

The chief operating decision maker of the company is the Chairman, President and Chief Executive Officer, who utilizes EBIT as the primary measure of profit and loss in assessing the results of each segment’s operations. EBIT includes operating income and other income and expenses. Items we do not include in EBIT are income taxes and financing costs, including interest expense, each of which we evaluate on a consolidated basis. Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the years ended December 31, 2014, 2013 and 2012 are shown in the following tables.

2014

In millions	**Distribution operations**	**Retail operations**	**Wholesale services** (1)	**Midstream operations**	**Other segments** (2)	**Intercompany eliminations**	**Consolidated**
Operating revenues from external parties	$3,802	$994	$578	$88	$7	$(84)	$5,385
Intercompany revenues	199	-	-	-	-	(199)	-
Total operating revenues	4,001	994	578	88	7	(283)	5,385
Operating expenses							
Cost of goods sold	2,223	683	77	57	-	(275)	2,765
Operation and maintenance	699	147	75	26	-	(8)	939
Depreciation and amortization	317	28	1	18	16	-	380
Taxes other than income taxes	189	4	3	6	6	-	208
Total operating expenses	3,428	862	156	107	22	(283)	4,292
Gain (loss) on disposition of assets	-	-	3	-	(1)	-	2
Operating income (loss)	573	132	425	(19)	(16)	-	1,095
Other income (expense)	8	-	(3)	2	7	-	14
EBIT	$581	$132	$422	$(17)	$(9)	$-	$1,109
Identifiable and total assets (3)	$12,041	$670	$1,402	$694	$9,723	$(9,621)	$14,909
Capital expenditures	$715	$11	$2	$15	$26	$-	$769

2013

In millions	**Distribution operations**	**Retail operations**	**Wholesale services** (1)	**Midstream operations**	**Other segments** (2)	**Intercompany eliminations**	**Consolidated**
Operating revenues from external parties	$3,230	$858	$60	$74	$8	$(21)	$4,209
Intercompany revenues	182	-	-	-	-	(182)	-
Total operating revenues	3,412	858	60	74	8	(203)	4,209
Operating expenses							
Cost of goods sold	1,687	564	21	33	-	(195)	2,110
Operation and maintenance	687	132	49	24	3	(8)	887
Depreciation and amortization	339	27	1	17	13	-	397
Taxes other than income taxes	167	3	3	5	9	-	187
Total operating expenses	2,880	726	74	79	25	(203)	3,581
Gain on disposition of assets	-	-	11	-	-	-	11
Operating income (loss)	532	132	(3)	(5)	(17)	-	639
Other income (expense)	14	-	-	(5)	7	-	16
EBIT	$546	$132	$(3)	$(10)	$(10)	$-	$655
Identifiable and total assets (3)	$11,634	$685	$1,163	$713	$10,160	$(10,088)	$14,267
Capital expenditures	$684	$9	$2	$12	$24	$-	$731

2012

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other segments (2)	Intercompany eliminations	Consolidated
Operating revenues from external parties	$2,691	$733	$88	$78	$7	$(35)	$3,562
Intercompany revenues	167	2	-	-	-	(169)	-
Total operating revenues	2,858	735	88	78	7	(204)	3,562
Operating expenses							
Cost of goods sold	1,221	488	38	32	-	(196)	1,583
Operation and maintenance	642	114	48	19	1	(8)	816
Depreciation and amortization	347	18	2	14	13	-	394
Nicor merger expenses (4)	-	-	-	-	20	-	20
Taxes other than income taxes	140	4	4	5	6	-	159
Total operating expenses	2,350	624	92	70	40	(204)	2,972
Operating income (loss)	508	111	(4)	8	(33)	-	590
Other income	9	-	1	2	12	-	24
EBIT	$517	$111	$(3)	$10	$(21)	$-	$614
Identifiable and total assets (3)	$11,256	$506	$1,218	$720	$9,848	$(9,769)	$13,779
Capital expenditures	$649	$8	$3	$62	$53	$-	$775

(1) The revenues for wholesale services are netted with costs associated with its energy and risk management activities. A reconciliation of our operating revenues and our intercompany revenues for the years ended December 31, are shown in the following table. Wholesale services 2014 operating revenues are related to colder-than-normal weather and extreme volatility and are not indicative of future performance.

In millions	Third party gross revenues	Intercompany revenues	Total gross revenues	Less gross gas costs	Operating revenues
2014	$10,709	$718	$11,427	$10,849	$578
2013	7,681	417	8,098	8,038	60
2012	6,089	350	6,439	6,351	88

(2) Our other non-reportable segments now also include our investment in Triton, which was part of our cargo shipping segment that is classified as discontinued operations. For more information, see Note 14.

(3) Identifiable assets are those used in each segment's operations and exclude assets held for sale.

(4) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.

Note 14 - Discontinued Operations

On September 1, 2014, we closed on the sale of Tropical Shipping to an unrelated third party. The after-tax cash proceeds and distributions from the transaction were approximately $225 million. We determined that the cumulative foreign earnings of Tropical Shipping would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million, of which $31 million was recorded in the first quarter of 2014, and the remaining $29 million was recorded in the third quarter of 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash.

During the first quarter of 2014, based upon the negotiated sales price, we also recorded a goodwill impairment charge of $19 million, for which there is no income tax benefit. Additionally, we recognized a total of $7 million charge in the second and third quarters of 2014 related to the suspension of depreciation and amortization for assets that we were not compensated for by the buyer.

The assets and liabilities of Tropical Shipping classified as held for sale on the Consolidated Statements of Financial Position are as follows:

In millions	**December 31, 2013**
Current assets	
Cash and cash equivalents	$24
Short-term investments	1
Receivables	36
Inventories	9
Other	1
Total current assets	71
Long-term assets and other deferred debits	
Property, plant and equipment, net	124
Goodwill	61
Intangible assets	19
Other	8
Total long-term assets and other deferred debits	212
Total assets held for sale	$283
Current liabilities	
Accrued expenses	$7
Other accounts payable - trade	11
Other	22
Total liabilities held for sale	$40

The financial results of these businesses are reflected as discontinued operations, and all prior periods presented have been recast to reflect the discontinued operations. The components of discontinued operations recorded on the Consolidated Statements of Income as of December 31, are as follows:

In millions	**2014**	**2013**	**2012**
Operating revenues	$243	$365	$342
Operating expenses			
Cost of goods sold	149	222	208
Operation and maintenance (1)	75	110	106
Depreciation and amortization (2)	5	19	22
Taxes other than income taxes	5	6	6
Loss on sale and goodwill impairment (3)	28	-	-
Total operating expenses	262	357	342
Operating (loss) income	(19)	8	-
(Loss) income before income taxes	(19)	8	-
Income tax expense (4)	(61)	3	(1)
(Loss) income from discontinued operations, net of tax	$(80)	$5	$1

(1) Includes $1 million for another business not related to Tropical Shipping that we discontinued in 2014 and was included in our "other" non-reportable segment.

(2) We ceased depreciating and amortizing Tropical Shipping's assets on April 4, 2014, as a result of entering into an agreement to sell this business and the assets were classified as held for sale.

(3) Primarily relates to the suspension of depreciation and amortization during 2014 totaling $7 million, and $19 million of goodwill attributable to Tropical Shipping that was impaired as of March 31, 2014, based on the negotiated sales price.

(4) Includes $60 million that was recorded in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded.

Note 15 - Selected Quarterly Financial Data (Unaudited)

The variance in our quarterly earnings is primarily the result of the seasonal nature of the distribution of natural gas to customers, the volatility within our wholesale services segment and the sale of our cargo shipping segment in 2014. During the Heating Season, natural gas usage and operating revenues are generally higher at our distribution operations and retail operations segments as more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. However, our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively uniformly over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality.

Our 2014 operating revenues and operating income were higher than 2013, primarily as a result of significantly colder-than-normal weather in 2014, volatility in the natural gas market and transportation constraints in the Northeast and Midwest. Our quarterly financial data for 2014 and 2013 are summarized below.

In millions, except per share amounts	**March 31**	**June 30**	**September 30**	**December 31**
2014				
Operating revenues	$2,462	$889	$589	$1,445
Operating income	592	139	78	286
EBIT	595	141	81	292
Income from continuing operations	346	59	23	152
Income from continuing operations attributable to AGL Resources Inc.	334	57	23	148
(Loss) income from discontinued operations, net of tax	(50)	1	(31)	-
Net income (loss) attributable to AGL Resources Inc.	284	58	(8)	148
Basic earnings (loss) per common share:				
Continuing operations	2.82	0.48	0.19	1.24
Discontinued operations	(0.43)	0.01	(0.25)	-
Diluted earnings (loss) per common share:				
Continuing operations	2.81	0.48	0.19	1.24
Discontinued operations	(0.43)	0.01	(0.25)	-
2013				
Operating revenues	$1,612	$805	$574	$1,218
Operating income	290	113	70	166
EBIT	295	119	77	164
Income from continuing operations	159	45	24	80
Income from continuing operations attributable to AGL Resources Inc.	149	44	24	73
Income (loss) from discontinued operations, net of tax	1	(1)	1	4
Net income attributable to AGL Resources Inc.	150	43	25	77
Basic earnings (loss) per common share:				
Continuing operations	1.27	0.38	0.20	0.61
Discontinued operations	0.01	(0.01)	0.01	0.03
Diluted earnings (loss) per common share:				
Continuing operations	1.26	0.38	0.20	0.61
Discontinued operations	0.01	(0.01)	0.01	0.03

Our basic and diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per common share attributable to AGL Resources Inc. common shareholders shown in the Consolidated Statements of Income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of December 31, 2014. No system of controls, no matter how well-designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases. Our disclosure controls and procedures, however, are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation and considering the remediation efforts described below, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014. Our disclosure controls and procedures are designed to ensure that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Remediation of Previously Disclosed Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014, we did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company's consolidated financial statements. Our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were not effective as of September 30, 2014 because of the material weakness.

We revised our consolidated financial statements for the years ended December 31, 2013, 2012 and 2011, for each of the quarterly periods during the year ended December 31, 2013, and for the quarters ended March 31, 2014 and June 30, 2014 to reflect certain accounting adjustments. We amended our Annual Report on Form 10-K/A for the year ended December 31, 2013, and our Quarterly Reports on Form 10-Q/A for the quarterly periods ending March 31, 2014 and June 30, 2014, to reflect those adjustments and the conclusions by our principal executive officer and our principal financial officer that our disclosure controls and procedures were not effective and by our management that our internal control over financial reporting were not effective as of December 31, 2013. Refer to "Management's Annual Report on Internal Control over Financial Reporting" within Item 8 and Item 9A Controls and Procedures in our Annual Report on Form 10-K/A for the year ended December 31, 2013, for further discussion of our material weakness in internal control over financial reporting.

We committed to remediating the material weakness and, as such, implemented changes to our internal control over financial reporting. We implemented additional procedures to address the underlying causes of the material weakness prior to filing our amended 2013 Annual Report on Form 10-K/A, and continued to implement changes and improvements in our internal control over financial reporting to remediate the control deficiency that caused the material weakness. During the fourth quarter of 2014, the following actions have been implemented:

- Completed training for all appropriate personnel regarding the applicable accounting guidance and requirements through internal training meetings and training by an outside expert to employees in technical, general and regulatory accounting functions, internal audit, and management positions.
- Reviewed all regulatory programs to ensure the proper evaluation of deferral components and proper treatment of allowed versus incurred costs pursuant to the relevant accounting guidance.
- Created a process and designed controls to capture and calculate allowed versus incurred costs and to record appropriate amounts in the consolidated financial statements. We identified appropriate processes, reviews and other controls to ensure accurate amounts were appropriately reflected in our consolidated financial statements.
- Conducted a review of our organization structure, reporting relationships and adequacy of staffing levels and made specific staffing changes as a result of our review.

- The procedures described above have been implemented and controls have been successfully tested.

Management is committed to a strong internal control environment. With full implementation and testing of the design and operating effectiveness of the newly implemented and revised controls, the actions described above successfully remediated the material weakness in our internal control over financial reporting and our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective and our management concluded that our internal control over financial reporting were effective as of December 31, 2014.

Changes in Internal Control over Financial Reporting

The changes in the aforementioned remediation efforts were changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Reports of Management and Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

Management has assessed, and our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited, our internal control over financial reporting as of December 31, 2014. The unqualified reports of management and PricewaterhouseCoopers LLP are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 59	
Chairman, President and Chief Executive Officer	October 2007 - Present
Andrew W. Evans, Age 48	
Executive Vice President and Chief Financial Officer	November 2010 - Present
Executive Vice President, Chief Financial Officer and Treasurer	June 2009 - November 2010
Henry P. Linginfelter, Age 54	
Executive Vice President, Distribution Operations	December 2011 - Present
Executive Vice President, Utility Operations	June 2007 - December 2011
Melanie M. Platt, Age 60	
Executive Vice President, Chief People Officer	December 2011 - Present
Senior Vice President, Human Resources and Marketing Communications	November 2008 - December 2011
Paul R. Shlanta, Age 57	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 - Present
Peter I. Tumminello, Age 52	
Executive Vice President, Wholesale Services, and President Sequent	December 2011 - Present
President, Sequent	April 2010 - December 2011
Executive Vice President, Business Development and Support, Sequent	February 2007 - April 2010

The other information required by this item with respect to directors will be set forth under the captions “Proposal 1 - Election of Directors,” “Corporate Governance - Ethics and Compliance Program,” and “Corporate Governance - Committees of the Board” in the Proxy Statement for our 2015 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions “Compensation Committee Report,” “Compensation Committee Interlocks and Insider Participation,” “Director Compensation,” “Compensation

Discussion and Analysis" and "Executive Compensation" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption "Compensation Committee Report" which is specifically not so incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be set forth under the captions "Security Ownership of Certain Beneficial Owners and Management" and "Executive Compensation - Equity Compensation Plan Information" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth under the captions "Corporate Governance - Director Independence" and "- Policy on Related Person Transactions" and "Certain Relationships and Related Transactions" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under the caption "Proposal 2 - Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2015" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

- Report of Independent Registered Public Accounting Firm
- Management's Report on Internal Control Over Financial Reporting

(1) Financial Statements Included in Item 8 are the following:

- Report of Independent Registered Public Accounting Firm
- Management's Report on Internal Control Over Financial Reporting
- Consolidated Statements of Financial Position as of December 31, 2014 and 2013
- Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Equity for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012
- Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2014. Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

(3) Exhibits

Exhibit Number	Description of Exhibit	Filer	The Filings Referenced for Incorporation by Reference
2.1	Agreement and Plan of Merger, as amended, dated December 6, 2010	AGL Resources	December 7, 2010, Form 8-K, Exhibit 2.1
2.2	Waiver entered into as of February 4, 2011	AGL Resources	February 9, 2011, Form 8-K, Exhibit 2.1
2.3	Stock Purchase Agreement by and among Aqua Acquisition Corp., Ottawa Acquisition LLC and Birdsall, Inc.(1)	AGL Resources	November 25, 2014, Form 10-Q/A, Exhibit 2
3.1	Amended and Restated Articles of Incorporation	AGL Resources	December 13, 2011, Form 8-K, Exhibit 3.1
3.2	Bylaws, as amended	AGL Resources	July 31, 2014, Form 8-K, Exhibit 3.1
4.1	Specimen Form of Common Stock certificate	AGL Resources	September 30, 2007, Form 10-Q, Exhibit 4.1

4.2.a	Form of AGL Capital Corporation 6.00% Senior Notes due 2034	AGL Resources	September 27, 2004, Form 8-K, Exhibit 4.1
4.2.b	Form of Guarantee of AGL Resources Inc. dated September 27, 2004	AGL Resources	September 27, 2004, Form 8-K, Exhibit 4.3
4.3.a	AGL Capital Corporation 4.95% Senior Notes due 2015	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.1
4.3.b	Guarantee of AGL Resources Inc. dated December 20, 2004	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.3
4.4.a	AGL Capital Corporation 6.375% Senior Notes due 2016	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.1
4.4.b	Guarantee of AGL Resources Inc. dated December 14, 2007	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.2
4.5.a	AGL Capital Corporation 5.25% Senior Notes due 2019	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.1
4.5.b	Guarantee of AGL Resources Inc. dated August 10, 2009	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.2
4.6.a	AGL Capital Corporation 5.875% Senior Notes due 2041	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.1
4.6.b	Guarantee of AGL Resources Inc. dated March 21, 2011	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.2
4.7.a	Form of AGL Capital Corporation 3.50% Senior Notes due 2021	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.1
4.7.b	Form of Guarantee of AGL Resources Inc. dated September 2011	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.2
4.8.a	Form of AGL Capital Corporation Series A Senior Notes due 2016	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.1
4.8.b	Form of AGL Capital Corporation Series B Senior Notes due 2018	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.2
4.9.a	AGL Capital Corporation 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.9.b	AGL Resources Inc. Guarantee related to the 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.10.a	Indenture dated December 1, 1989	Atlanta Gas Light	File No. 33-32274, Form S-3, Exhibit 4(a)
4.10.b	First Supplemental Indenture dated March 16, 1992	Atlanta Gas Light	File No. 33-46419, Form S-3, Exhibit 4(a)
4.11	Indenture dated February 20, 2001	AGL Resources	September 17, 2001, File No. 333-69500, Form S-3, Exhibit 4.2
4.12.a	Indenture dated January 1, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.01
4.12.b	Indenture dated February 9, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.02
4.12.c	Supplemental Indenture dated February 15, 1998	Nicor Gas	December 31, 1997, Form 10-K, Exhibit 4.19
4.12.d	Supplemental Indenture dated May 15, 2001	Nicor Gas	July 20, 2001, File No. 333-65486, Form S-3, Exhibit 4.18
4.12.e	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.09
4.12.f	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.10
4.12.g	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.11
4.12.h	Supplemental Indenture dated December 1, 2006	Nicor Gas	December 31, 2006, Form 10-K, Exhibit 4.11
4.12.i	Supplemental Indenture dated August 1, 2008	Nicor Gas	September 30, 2008, Form 10-Q, Exhibit 4.01
4.12.j	Supplemental Indenture dated July 23, 2009	Nicor Gas	June 30, 2009, Form 10-Q, Exhibit 4.01
4.12.k	Supplemental Indenture dated February 1, 2011	Nicor Gas	December 31, 2010, Form 10-K, Exhibit 4.12
4.12.l	Supplemental Indenture dated October 26, 2012	Nicor Gas	September 30, 2012, Form 10-Q, Exhibit 4
10.1.a +	2006 Non-Employee Directors Equity Compensation Plan, amended and restated as of December 9, 2011	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.2
10.1.b +	1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 1997, Form 10-Q, Exhibit 10.1.b
10.1.c +	First Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	March 31, 2000, Form 10-Q, Exhibit 10.5
10.1.d +	Second Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.4
10.1.e +	Third Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.5
10.1.f +	Fourth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.m

10.1.g +	Fifth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.l
10.1.h +	Form of Stock Award Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.aj
10.1.i +	Form of Nonqualified Stock Option Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.ak
10.1.j +	Form of Director Indemnification Agreement dated April 28, 2004	AGL Resources	June 30, 2004, Form 10-Q, Exhibit 10.3
10.1.k +	Long-Term Incentive Plan, as amended and restated as of January 1, 2002	AGL Resources	March 31, 2002, Form 10-Q, Exhibit 99.2
10.1.l +	First amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.b
10.1.m +	Second amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.l
10.1.n +	Third amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ad
10.1.o +	Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	March 14, 2011, Schedule 14A, Annex A
10.1.p +	Form of Restricted Stock Unit Agreement under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2011, Form 10-K, Exhibit 10.1.ae
10.1.q +	Form of Restricted Stock Agreement under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2011, Form 10-K, Exhibit 10.1.af
10.1.r +	Form of Performance Share Unit Award under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1r
10.1.s +	2007 Omnibus Performance Incentive Plan	AGL Resources	March 19, 2007, Schedule 14A, Annex A
10.1.t +	First Amendment to the 2007 Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ai
10.1.u +	Form of Incentive Stock Option Agreement – 2007 Omnibus Performance Incentive Plan	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.b
10.1.v +	Form of Nonqualified Stock Option Agreement – 2007 Omnibus Performance Incentive Plan	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.c
10.1.w +	Form of Incentive Stock Option Agreement and Nonqualified Stock Option Agreement for key employees (LTIP)	AGL Resources	September 30, 2004, Form 10-Q, Exhibit 10.1
10.1.x +	Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.1
10.1.y +	Form of Nonqualified Stock Option Agreement with the reload provision (Officer Incentive Plan)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.2
10.1.z +	Nonqualified Savings Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.av
10.1.aa +	First Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.aa
10.1.ab +	Second Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ab
10.1.ac +	Third Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ac
10.1.ad +	Description of Supplemental Executive Retirement Plan for John W. Somerhalder II	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ay
10.1.ae +	Excess Benefit Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.az
10.1.af +	Form of Continuity Agreement dated December 19, 2013	AGL Resources	December 19, 2013, Form 8-K, Exhibit 10.1
10.1.ag +	Description of compensation for each of John W. Somerhalder II, Andrew W. Evans, Henry P. Linginfelter, Paul R. Shlanta and Peter I. Tumminello (our Named Executive Officers for the year ended December 31, 2014)	AGL Resources	Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held April 29, 2014, filed March 18, 2014.
10.2.a	Form of Commercial Paper Dealer Agreement	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.79
10.2.b	Guarantee dated October 5, 2000 of payments on	AGL Resources	September 30, 2000, Form 10-K, Exhibit

	promissory notes		10.80
10.4	Note Purchase Agreement dated August 31, 2011	AGL Resources	September 7, 2011, Form 8-K, Exhibit 10.1
10.5	Final Allocation Agreement dated January 3, 2008	Nicor	December 31, 2007, Form 10-K, Exhibit 10.64
10.6	Second Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC dated September 6, 2013 by and between Georgia Natural Gas Company and Piedmont Energy Company	AGL Resources	September 30, 2013, Form 10-Q, Exhibit 10
10.7	Credit Agreement dated as of December 15, 2011(2)	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.1
10.8.a	Amended and Restated Credit Agreement dated as of November 10, 2011(3)	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.1
10.8.b	Guarantee Agreement dated as of November 10, 2011	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.2
10.9	Bank Rate Mode Covenants Agreement, dated as of February 26, 2013	AGL Resources	March 1, 2013, Form 8-K, Exhibit 10.1
10.10	Loan Agreement dated as of February 1, 2013	AGL Resources	March 1, 2013, Form 8-K, Exhibit 10.2
10.11	Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.1
10.12	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.2
10.13	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.3
10.14	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.4
12	Statement of Computation of Ratio of Earnings to Fixed Charges	AGL Resources	Filed herewith
14	Code of Ethics for the Chief Executive Officer and Senior Financial Officers	AGL Resources	December 31, 2004, Form 10-K, Exhibit 14
21	Subsidiaries of AGL Resources Inc.	AGL Resources	Filed herewith
23	Consent of PricewaterhouseCoopers LLP	AGL Resources	Filed herewith
24	Powers of Attorney	AGL Resources	Included on signature page hereto
31.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
31.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
32.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
32.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
101.INS	XBRL Instance Document	AGL Resources	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema	AGL Resources	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	AGL Resources	Filed herewith
101.DEF	XBRL Taxonomy Definition Linkbase	AGL Resources	Filed herewith
101.LAB	XBRL Taxonomy Extension Labels Linkbase	AGL Resources	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	AGL Resources	Filed herewith

\+ Management contract, compensatory plan or arrangement.

(1) Portions of this exhibit have been omitted pursuant to a request for confidential treatment with the SEC. The omitted portions have been separately filed with the SEC.

(2) In November 2013, the Credit Agreement commitment terms were extended to a maturity date of December 15, 2017 via an approved extension request.

(3) In November 2013, the Amended and Restated Credit Agreement commitment terms were extended to a maturity date of November 10, 2017 via an approved extension request.

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

(c) Financial statement schedules filed as part of this report.

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 11, 2015.

AGL RESOURCES INC.

By: /s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2014, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 11, 2015.

Signatures	Title
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Bryan E. Seas Bryan E. Seas	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ Sandra N. Bane Sandra N. Bane	Director
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director
/s/ Norman R. Bobins Norman R. Bobins	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Brenda J. Gaines Brenda J. Gaines	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director

Signatures	Title
/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director
/s/ Dennis M. Love Dennis M. Love	Director
/s/ Dean R. O’Hare Dean R. O’Hare	Director
/s/ Armando J. Olivera Armando J. Olivera	Director
/s/ John E. Rau John E. Rau	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Henry C. Wolf Henry C. Wolf	Director

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2014.

		Additions			
In millions	**Balance at beginning of period**	**Charged to costs and expenses**	**Charged to other accounts**	**Deductions**	**Balance at end of period**
2012					
Allowance for uncollectible accounts	$17	$25	$3	$(17)	$28
Income tax valuation	3	-	19	-	22
2013					
Allowance for uncollectible accounts	$28	$37	$-	$(36)	$29
Income tax valuation	22	-	-	-	22
2014					
Allowance for uncollectible accounts	$29	$54	$2	$(50)	$35
Income tax valuation	22	-	-	(2)	20

Exhibit 6

Southern Company 2014 Summary Annual Report

Doing Energy Better

MAKING It Better

Southern Company is committed to the development of the full portfolio of fuel sources for energy generation: New nuclear, 21st century coal, natural gas and renewables such as wind and solar, deployed in tandem with an emphasis on energy efficiency. By utilizing a variety of technologies and abundant natural resources, this environmentally responsible approach ensures that our subsidiaries' ability to produce clean, safe, reliable and affordable energy is not reliant upon any single source of generation.

[See Page 6]

Mark Rauckhorst, Construction Vice President (left), and Vanderian Floyd, Performance Improvement Manager (right), assess construction of Vogtle units 3 and 4 at Georgia Power's Plant Vogtle.

MOVING It Better

We take great pride in our ability to deliver electricity throughout our system with industry-leading reliability. Southern Company has invested nearly $7 billion in smart grid technology that gives us the means to both predict and adapt to the variable energy needs of customers. No less important are the dedicated line crews who work diligently through all kinds of weather conditions to maintain the transmission and distribution network.

[See Page 12]

So Customers Can USE It Better

Everything we do to make and move energy better is ultimately for the benefit of customers. But generating electricity cleanly, safely and efficiently and delivering it to the grid is only part of our mission. We work hard to maintain exceptional reliability and to keep rates affordable. Our traditional operating companies also work directly with customers to help them find better ways to manage their energy consumption more efficiently.

[See Page 18]

Contents

Thomas A. Fanning

Chairman, President & CEO
Southern Company

Dear Fellow Shareholders,

Southern Company's franchise operations have never performed better than they did in 2014. We continued to provide the most outstanding customer service in our industry. In terms of system reliability, we continued to set–and raise–the bar. We grew our portfolio of wholesale renewable assets and made significant progress on major construction projects.

In these and many other areas, Southern Company's franchise business continues to lead the way as we strengthen existing operations and seek new opportunities to grow and expand our reach for the benefit of the customers and communities we serve.

As evidenced throughout this report, we are steadfastly committed to 'doing energy better.' This speaks to our goal to make, move and help customers use energy more efficiently than anyone else in our industry. With that mission in mind, we have sharpened our focus on innovation.

Innovation has been a hallmark of Southern Company since its inception, and in 2014 we were very intentional in our efforts to leverage the creativity of our workforce. In May, we announced an internal competition to tap into that creative energy and surface fresh ideas. Known as SO Prize, the competition was designed to recognize system employees who devised the most inventive solutions to address the various challenges of the electric utility industry, and to position Southern Company for continued success in the years to come.

The response was overwhelming, with more than 500 individuals and cross-functional teams submitting nearly 1,000 ideas. From among those, we identified six in particular as having transformative potential. Their stories are detailed elsewhere in this report, and I am confident that you will be extremely impressed with the depth and breadth of thinking represented.

The complete story of 2014 is perhaps best told through a brief review of progress on each of our five strategic priorities:

Excel at the Fundamentals

Nothing is more fundamental to our business than customer service. Southern Company and its four traditional operating companies occupied the top five spots in the most recent Customer Value Benchmark survey, our annual peer comparison of U.S. electric utilities. Those of our traditional operating companies that were rated in the J.D. Power and Associates American Customer Satisfaction Survey all ranked either first or second in their respective categories. Alabama Power was also named the Most Trusted Residential Electric Utility in America by Lifestory Research, an independent research firm.

Our transmission and distribution businesses performed superbly, setting all-time record lows for the frequency and duration of transmission outages, as well as an all-time system record for distribution outage frequency. And these results are just the latest in a 12-year trend of improved performance.

Achieve Success with Major Construction Projects

Work continues on Georgia Power's Vogtle units 3 and 4, where our focus continues to be on safety and quality, with construction of the two nuclear islands as our critical path going forward. Milestones achieved in 2014 include the placement of the Unit 4 containment vessel bottom head, the Unit 3 lower ring and the CA20 critical module, which houses plant components and the used fuel storage area.

Vogtle construction has not been without its challenges. We received a revised forecast from our contractor that reflects an 18-month delay from previously estimated in-service dates. It is significant to note, however, that the proposed schedule does not change the range of the expected customer rate impact. The forecasted effect on customer rates is still less than originally anticipated, with the overall impact projected to be 6 to 8 percent, compared with 12 percent when certified by the Georgia Public Service Commission in 2009. These new units will fuel a growing Georgia for at least 60 years, resulting in significant lifecycle savings. Building them safely–and correctly–is far more important than building them quickly.

At Mississippi Power's Integrated Gasification Combined Cycle project in Kemper County, Mississippi, construction is nearly complete and we have completed the first firing of the facility's gasifier burners, which functioned as expected. We anticipate our first syngas production in the third quarter of 2015. Operational training and control systems validation, as well as start-up and commissioning activities, are all underway and progressing well.

Support the Building of a National Energy Policy

We continue to advocate for a common sense national energy policy that embraces the full energy portfolio and places a premium on energy innovation and the restoration of America's financial integrity. Our vision for the full energy portfolio includes new nuclear, 21st century coal, natural gas and renewables such as wind and solar, together with an emphasis on energy efficiency.

Promote Energy Innovation

We continue to produce and purchase power from a variety of renewable energy sources. Our traditional operating companies have the flexibility to serve customers with that generated energy, or sell some or all of it–or the associated renewable energy credits–to third parties.

In 2014, we continued to grow our wholesale renewable portfolio through our Southern Power subsidiary, which added three new solar facilities in California and New Mexico. Southern Power is also developing a 131-megawatt solar plant in Taylor County, Georgia, and has acquired two other solar projects in Georgia that will provide an additional 99 megawatts. Along with the expansion of its solar assets, Southern Power has also entered into an agreement to acquire the 299-megawatt Kay Wind project in Oklahoma.

Upon completion of these facilities, Southern Power is expected to own more than 970 megawatts of renewable energy generating capacity, and is clearly becoming an industry leader in the advancement and operation of renewable energy technologies.

In addition, Gulf Power has filed for approval to purchase power from Kingfisher Wind in Oklahoma, and Georgia Power is evaluating wind turbines on Skidaway Island, Georgia.

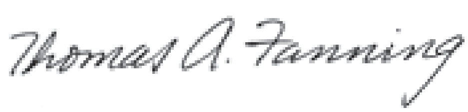
Value and Develop Our People

Fortune magazine recently named Southern Company to its "World's Most Admired Companies" list as a top utility worldwide for the sixth consecutive year, and we were cited as one of the 40 Best Companies for Diversity by Black Enterprise magazine. G.I. Jobs magazine ranked Southern Company first among utilities in its Top 100 Military Friendly Employers, the eighth consecutive year we have received the top ranking. In 2014, we completed 481 transfers of employees between our various subsidiaries, broadening their experience and knowledge of our industry and business operations.

These and many other accomplishments are the direct result of an unwavering focus on the core values that have shaped our company's identity since its inception. Going forward, we remain anchored in those values. In particular, our customer-focused business model will continue to be the guiding principle for all that we do. As we turn our attention to the future, I am confident that the opportunities we encounter will give rise to even greater creativity and innovation throughout our organization, even as we remain rooted in this firm foundation.

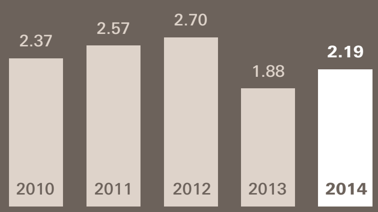
Thank you for your continued confidence in Southern Company. Our management and employees remain diligent in their efforts to provide exceptional shareholder value. It is an honor to serve you.

Sincerely,



Thomas A. Fanning
March 26, 2015

Financial Highlights



Basic Earnings Per Share
(In Dollars)

Basic Earnings Per Share Excluding Kemper IGCC Impacts, Leveraged Lease Restructure Charge, and MC Asset Recovery Insurance Settlements*
(In Dollars)

** Not a financial measure under generally accepted accounting principles. See Glossary on page 36 for additional information and specific adjustments made to this measure by year.*

Operating Revenues
(In Billions of Dollars)

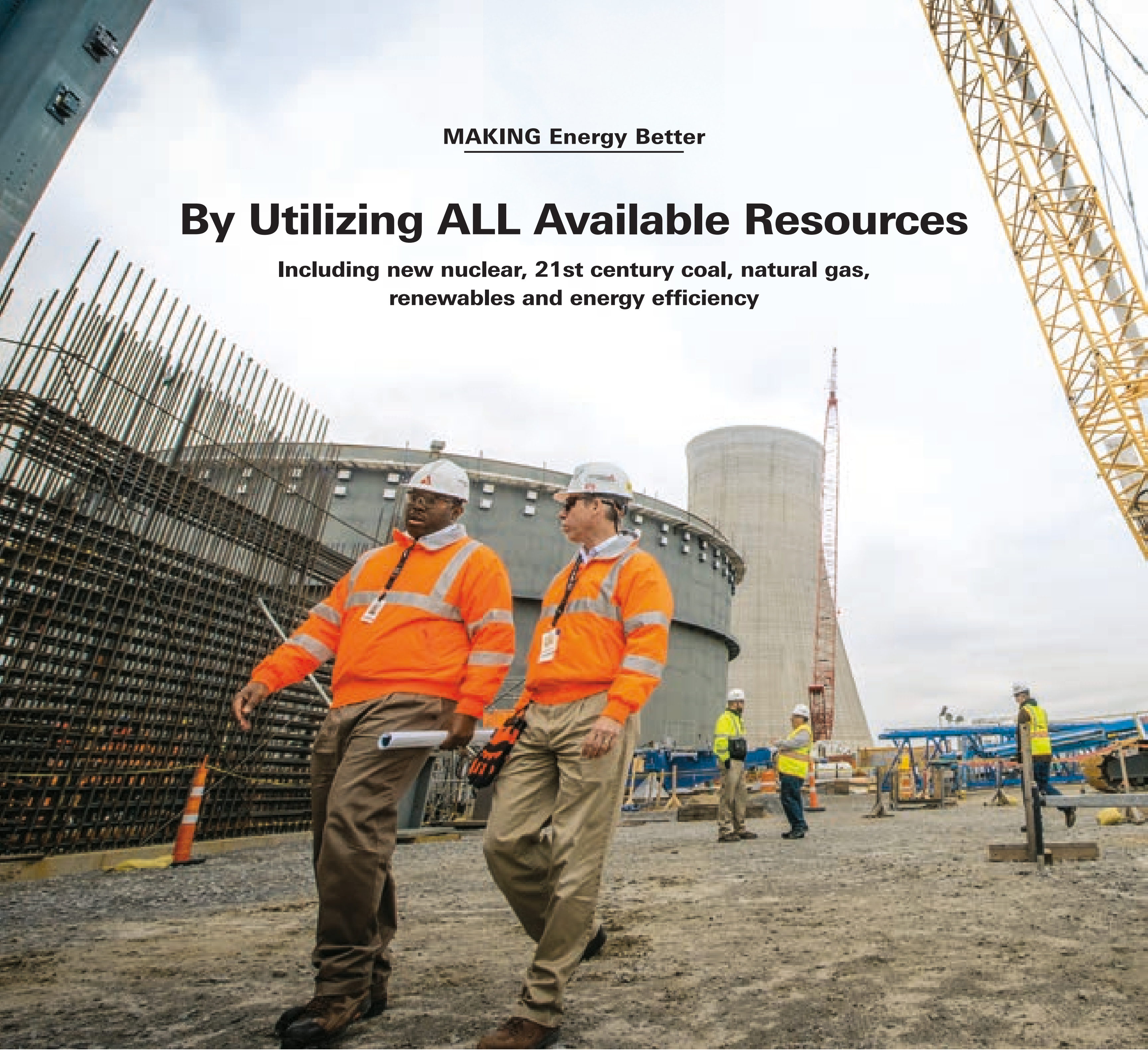
Return On Average Common Equity
(Percent)

	2014	2013	Change
Operating Revenues *(In Millions)*	**$18,467**	$17,087	8.1 %
Earnings *(In Millions)*	**$1,963**	$1,644	19.4 %
Basic Earnings Per Share	**$2.19**	$1.88	16.5 %
Diluted Earnings Per Share	**$2.18**	$1.87	16.6 %
Dividends Per Share *(Amount Paid)*	**$2.0825**	$2.0125	3.5 %
Dividend Yield *(Year-End, Percent)*	**4.2**	4.9	(14.3)%
Average Shares Outstanding *(In Millions)*	**897**	877	2.3 %
Return On Average Common Equity *(Percent)*	**10.08**	8.82	14.3 %
Book Value Per Share	**$21.98**	$21.43	2.6 %
Market Price Per Share *(Year-End, Closing)*	**$49.11**	$41.11	19.5 %
Total Market Value of Common Stock *(Year-End, In Millions)*	**$44,581**	$36,468	22.2 %
Total Assets *(In Millions)*	**$70,923**	$64,546	9.9 %
Total Kilowatt-Hour Sales *(In Millions)*	**194,425**	183,401	6.0 %
Retail	**161,639**	156,457	3.3 %
Wholesale	**32,786**	26,944	21.7 %
Total Traditional Operating Company Customers *(Year-End, In Thousands)*	**4,504**	4,467	0.8 %

MAKING Energy Better

By Utilizing ALL Available Resources

Including new nuclear, 21st century coal, natural gas, renewables and energy efficiency



(Above) The construction of Vogtle units 3 and 4 is the largest job-producing project in the state of Georgia, employing more than 5,500 people in construction, and is expected to create 800 permanent jobs once the units go on line. Upon completion of the new units, Plant Vogtle is expected to generate more electricity than any other U.S. nuclear facility; **(Left)** Construction nears completion at the Kemper County, Mississippi, coal gasification facility; **(Middle)** Plant Franklin, a natural gas facility in Smiths, Alabama; **(Right)** Cimarron Solar Facility, part of the Southern Company system's growing renewable energy portfolio

Just as an astute investor understands the importance of a diversified investment portfolio, Southern Company is committed to a diversified portfolio of options for power generation that makes use of a wide range of available fuel sources. This approach allows for flexibility in choosing the most economical and efficient means of providing clean, safe, reliable and affordable electricity to customers throughout the Southeast.

As a starting point, we believe nuclear must be a dominant solution in a carbon-constrained world. The Southern Company system is pursuing the newest generation of nuclear technology in the world today, and we are leading the nuclear renaissance with the construction of new units at Plant Vogtle in Georgia.

Because coal remains such an abundant domestic resource, we have invested considerable time and energy exploring ways to use it in a more environmentally responsible manner. We have developed our own technology for coal gasification, and Mississippi Power is constructing a facility designed to use this traditional natural resource in an innovative way that will significantly reduce emissions.

With advances in drilling technology, we are now able to obtain affordable supplies of natural gas that were previously unobtainable. As a result, natural gas represented 40 percent of our fuel mix in 2014, and the Southern Company system has become the third-largest consumer of natural gas in the United States.

The Southern Company system is one of the largest owners of solar photovoltaic facilities in the U.S., generating energy that can be used to serve customers or sold by our traditional operating companies to third parties, with or without the associated renewable energy credits.

The benefit of this flexible, full portfolio strategy was apparent during the winter of 2014, when uncharacteristically cold temperatures across the Southeast and other parts of the nation resulted in an accelerated demand for natural gas, as well as a corresponding increase in the cost to purchase it. In response, we were able to seamlessly turn to other fuel sources for power generation to help keep costs low, even as we addressed increased customer demand.

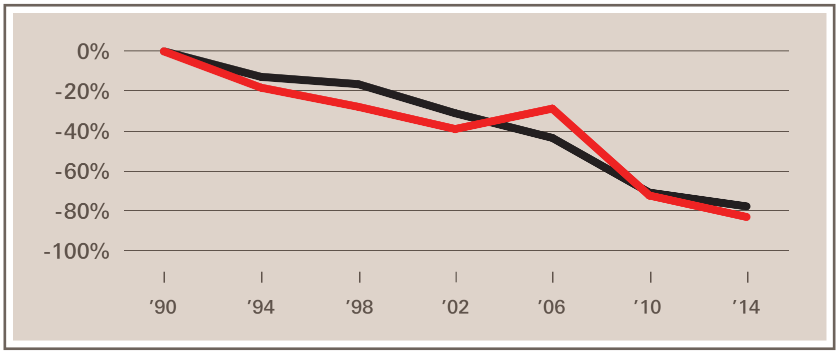
Fuel Flexibility *(Percent, GWHs of Energy)**

			2020 Range**	
	2000	2014	Low Gas Price	High Gas Price
Coal	78	40	21	49
Gas	4	40	55	27
Nuclear	16	16	18	18
Hydro/Other	2	4	6	6

** Includes purchased power. ** Illustrative ranges based on assumed natural gas prices of $2/mmBtu (Low Gas Price) and $14/mmBtu (High Gas Price). Assumptions have been selected to illustrate the Southern Company system's fuel flexibility and do not represent actual forecasts of future system fuel mix or natural gas prices.*

By Advancing Smarter Technologies
that Generate Cleaner Energy

With new nuclear, 21st century coal and a rapidly growing portfolio of renewables, the Southern Company system leads the way in clean power generation.



Southern Company System Emissions Trends
(Percent Change Since 1990 Levels)
• SULFUR DIOXIDE • • NITROGEN OXIDES •

The Southern Company system continues to develop and utilize the very latest in technological innovations to produce electricity more cleanly and efficiently. Since 1990, we have reduced major emissions by 80 percent, even as generating capacity increased by as much as 40 percent.

At Plant Vogtle, Georgia Power is building the first new nuclear reactors in the United States in 30 years, using the latest in nuclear technology. With virtually no emissions, nuclear power is one of the cleanest forms of generation available.

The Southern Company system is leading the way in coal gasification technology with our Transport Reactor Integrated Gasification process, or TRIG™. This process is currently being implemented at Mississippi Power's new coal-fired facility in Kemper County, Mississippi, where construction is nearing completion. When the facility is finished, Mississippi Power will take an otherwise unused natural resource–native Mississippi lignite–remove much of the CO_2 and generate electricity with a carbon footprint comparable to that of a similarly sized natural gas facility.

In Wilsonville, Alabama, we operate the National Carbon Capture Center on behalf of the U.S. Department of Energy. The center provides facilities for testing new technologies for flue gas and coal-derived syngas, helping to accelerate the development of cost-effective CO_2 capture technologies.

We continue to produce and purchase thousands of megawatt-hours from renewable projects, with the flexibility to serve the customers of our traditional operating companies with the generated energy, or sell some or all of the power or the associated renewable energy credits to third parties. Georgia Power has plans to build 30-megawatt solar installations at the Kings Bay Naval Submarine Base near St. Mary's, Georgia, and at three U.S. Army bases: Fort Stewart, near Savannah; Fort Benning, near Columbus; and Fort Gordon, near Augusta. Gulf Power is partnering with the U.S. Navy and U.S. Air Force to build solar farms at three different military installations in northwest Florida, and Alabama Power, Georgia Power and Gulf Power all have contracts to purchase power from wind facilities in Kansas and Oklahoma.

Meanwhile, Southern Power has been cleared to construct a 900-acre, 131-megawatt solar farm in Taylor County, Georgia and announced the acquisition of an additional 99 megawatts of generating capacity associated with two other Georgia facilities. With the completion of these and other projects, Southern Power is expected to own more than 970 megawatts of renewable energy generating capacity that is either already in operation or under development.

Construction nears completion at Mississippi Power's new integrated gasification combined cycle (IGCC) facility in Kemper County, Mississippi. When completed, this 21st century coal facility will utilize native Mississippi lignite to generate electricity with a carbon footprint comparable to a similarly sized natural gas facility.

SO PRIZE

Doing Energy Better

By Harnessing the Power of Innovation and Collaboration

In May of 2014, we announced an internal competition for system employees that aimed to harness the power of innovation and collaboration. The goal was to help the company "look around the corners of the future" and position itself for continued success.

Known as SO Prize, the competition was designed to recognize employees who devised the most inventive solutions to the various challenges faced by Southern Company and the electric utility industry, and to stimulate fresh ideas that could potentially drive future growth for years to come.

More than 500 individuals and teams submitted nearly 1,000 ideas. Many teams were made up of employees from different operating companies and subsidiaries, collaborating across geographic and business unit lines.

In October, six SO Prize winners were announced. The winning teams and individuals, along with a synopsis of their proposals, are highlighted throughout the pages of this publication. Pilot programs have been approved for all six concepts as the company continues to explore and evaluate the possibilities of each.

SO PRIZE

The Hydrogen Alternative

Chethan Acharya and Todd Wall envision a plan for using existing power plants to make hydrogen, which could be transported by liquid carriers to fuel stations using existing oil pipeline infrastructure. The gas could then be used to power proton-exchange membrane fuel cell vehicles on the open road or in industrial settings. Such a scenario could ultimately pave the way for a carbon-free hydrogen economy, with Southern Company positioned as the leading supplier of hydrogen for this market.

Team Members:
Chethan Acharya (SCS), Todd Wall (SCS)

SO PRIZE

Water, Water Everywhere

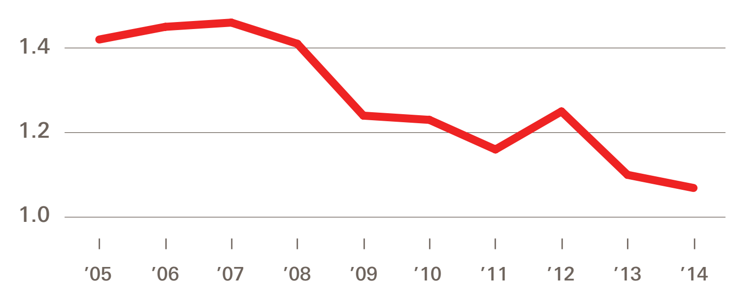
With 400 miles of coastal access and 27,000 miles of transmission line rights-of-way in the Southern Company system, Ray Smith envisions a grid of pipelines that move water to where it is needed. Desalination plants could be constructed to convert coastal seawater to fresh water and then pump it through pipelines along transmission rights-of-way. Providing the Southeast with a virtually unlimited source of water could help alleviate ongoing discussions between states over the current limited supply, and address local communities' concerns regarding droughts and water rationing.

Team Member:
Ray W. Smith (SCS)

As Proven by

Our Industry-Leading Reliability

The Southern Company system's Power Coordination Center, dedicated line crews and innovative technologies combine to ensure excellence in transmission and distribution.



SAIFI Performance

(In Number of Outages Per Customer)

System Average Interruption Frequency Index (SAIFI) is the standard industry index for measuring the number of outages experienced by an average customer in a year. Our 2014 SAIFI was 1.069 events, the best in Southern Company history.

You might say that Todd Lucas is an expert in keeping the lights on. As general manager of bulk power operations, Todd oversees the Power Coordination Center (PCC), which is responsible for maintaining a reliable and efficient transfer of energy throughout the system. PCC staff members work around the clock 365 days a year to monitor activity on the grid, and they oversee the transmission and distribution system at the highest level.

Throughout the Southeast, the diligent efforts of our traditional operating companies' line crews cannot be over-emphasized. In 2014, crews worked tirelessly to restore power to customers after outages caused by tornadoes and winter storms.

These dedicated men and women know that reliability is of critical importance to customers. Businesses require a high level of power quality in order to prevent incremental fluctuations in the flow of energy that might disrupt sophisticated electronic systems or industrial operations. And, of course, having a consistent and reliable source of energy is no less important to residential customers and their families.

Thanks to the efforts of these and many other system associates, 2014 saw yet another all-time record established for reliability on our transmission and distribution system, continuing a long-term positive trend of more than a decade.

On the technology front, we've been busy testing innovative power flow control technologies that improve the utilization of existing grid infrastructure at significant savings compared with traditional transmission line upgrades.

Ultimately, the combined impact of these individuals and deployed technologies converge to help maintain the industry-leading reliability that customers demand.

Todd Lucas (center), general manager of bulk power operations, consults with team members at the Southern Company system's state-of-the-art Power Coordination Center in Alabama.

MOVING Energy Better

Putting Customers First Makes For
Sweet Satisfaction

Southern Company's customer-focused business model is the linchpin of our success.

Andra Hall is laser-focused on keeping her customers satisfied. Of course, with friendly service and succulent confections like 'The Elvis' cupcake, it's hard to envision how patrons of CamiCakes Cupcakes could ever be anything less than satisfied. Named for Andra's daughter Camille (nicknamed "Cami"), CamiCakes offers dedicated fans throughout metro Atlanta a unique selection of baked delights.

Likewise, Georgia Power sales and efficiency representatives work hard to keep customers satisfied in their role as company liaisons with businesses like Andra's. They consult with local businesses to provide an analysis of their energy consumption, and make recommendations for more energy-efficient operations and potential dollar savings. For example, Andra's representative suggested that she operate the ovens in her production facility during off-peak hours for significant reductions in cost and usage.

Elsewhere, Georgia Power's new state-of-the-art Customer Resource Center (CRC) enhances customer satisfaction by catering to residential, commercial and industrial customers in a variety of innovative ways. The CRC offers information and demonstrations on electric transportation, comfort systems and cooking technologies, as well as manufacturing applications for industry and energy efficient ideas for the home, all under one roof.

CamiCakes Cupcakes owner Andra Hall and her employees adjust a display of delicious treats prior to the morning opening of one of her Atlanta stores. Georgia Power consults with Ms. Hall to help achieve optimal efficiency in energy consumption in her retail locations and production center.

SO PRIZE

Line Inspections Using UAVs

Today, aerial inspections of power lines are performed with manned aircraft. Paul Schneider and his team propose flight-based data collections by unmanned aerial vehicles (UAVs). UAVs are more cost-effective than helicopters and winged aircraft, and they enable closer inspection with less environmental impact. UAVs could also dramatically reduce the time between data collection flights that require air support. This proposal estimates that outages could be shortened by an average of 1.5 hours per outage through the use of UAVs—eliminating almost 11 days of outages every year.

Team Members:

Paul Schneider (GPC; pictured), Matt Clarkson (APC), Dexter Lewis (SCS), Drew McGuire (SCS), Patrick Norris (SCS), Ranato Salvaleon (GPC)

SO PRIZE

Dynamic Data

Alabama Power's James Young and his colleagues are convinced that the key to increasing customer satisfaction, loyalty and revenue lies in better understanding what individual customers want and treating them accordingly. The idea: Use data to identify customer priorities and proactively provide individualized solutions. Data analytics could provide actionable insights that enable the delivery of the right message to the right customer at the right time—or assist in the development of new product and service offerings while identifying the most cost-effective manner in which to implement them.

Team Members:

James Young (APC; pictured), **Noel Black** (SCS), **Chris Blake** (APC), **Stoney Burke** (SCS), **Hannah Flint** (SCS), **Joe Massari** (SCS), **Todd Perkins** (APC), **Tom Schmaeling** (APC), **Nick Sellers** (APC), **John Smola** (APC), **George Stegall** (APC), **Jeanne Wolak** (SCS)

By Delivering Reliable Service at Affordable Rates,
We're Providing Customers with Peace of Mind

Industry-leading reliability, energy-efficient homes and rates below the national average prove to be a winning combination.

Atlanta homeowner Larry Cummings and his wife, Cia, appreciate Georgia Power's reliable service and affordable rates. And as the owners of an almost totally rebuilt home, they also appreciate the energy-efficient features that their builder included on the advice of Georgia Power's energy consultants.

"We have great confidence in the reliability of the service we get from Georgia Power," says Larry. "We don't really have to think about it. That's not always the case with other utility providers. And when we first moved into our new home, we were able to establish service with just a single point of contact. For our family, that's really more important than the savings."

Southern Company's traditional operating companies work diligently to maintain transmission and distribution reliability, and to minimize service down time. But when the occasional planned or weather-related power outage occurs, customers are kept apprised of the latest outage status by a variety of means, including mobile apps, outage alerts, interactive outage maps and social media.

Of course, lower power bills don't hurt, either. According to Larry, "Affordable rates are important because our three children can consume a lot of energy. But because we've enjoyed consistently predictable rates, we've been able to budget in such a way as to direct household cash flow to other family priorities."


LED


76


USING Energy Better

Through Smarter Choices

Simple, common-sense choices can result in significant savings.

Since 2000, energy-efficiency programs have helped the Southern Company system reduce peak demand by 4,382 megawatts and avoid over 2.6 billion kilowatt-hours of energy use. That's enough electricity to power the cities of Birmingham, Alabama, Montgomery, Alabama and Savannah, Georgia for a year.

Pensacola, Florida, homebuilder Kevin Russell understands the value of energy efficiency in home construction, both for his own home and the homes he builds for his customers.

When building a home, Kevin works hand-in-glove with his Gulf Power residential energy consultant, Heather Madison, even before construction begins. Heather meets with Kevin and his team to consult on HVAC, insulation and other aspects of the home-building process, and she continues to visit the job site to assess the energy fitness of the home as construction progresses. She also counsels Kevin on options for the most efficient lighting fixtures, heat pumps, water heaters and other appliances that will work within his customers' budgets.

In his own home, Kevin uses energy-efficient lighting fixtures and appliances. Kevin appreciates the fact that energy efficiency helps keep his monthly power bill low. As part of Gulf Power's EarthCents program, Gulf Power residential energy consultants also work directly with homeowners like Kevin to help them assess and better control energy usage in their homes. Residential energy consultants in Southern Company's traditional operating companies are available to perform energy audits, conduct new home inspections and discuss incentive programs.

At the end of the day, our goal is to help customers like Kevin use energy better by making smarter and more energy-efficient choices both in new home construction and in existing homes.

(Above) Homeowner–and homebuilder–Kevin Russell installs an energy-efficient light-emitting diode (LED) light bulb; **(Left)** An electric charger for plug-in electrical vehicles (PEVs); some 10,000 PEVs are registered in the Southern Company service territory; **(Middle)** An energy-efficient programmable thermostat can help lower energy costs; **(Right)** An ENERGY STAR-rated clothes washer uses about 20 percent less energy than regular washers.

SO PRIZE

Empowering Customers with More Choices

Gulf Power's Lisa Roddy believes customers should have more options, similar to the customized cell phone plans offered by wireless carriers. For example, customers might pay a set amount for unlimited usage or pay only for what they use. They could potentially purchase charging stations for electric vehicles or surge protection at a fixed price. Lisa envisions that customers might even be able to purchase blocks of renewable energy or select options to finance solar power for their homes.

Team Member:
Lisa Roddy (Gulf)

SO PRIZE

Fueling the PEV Revolution

Bryan Coley, John Socha and their team envision a comprehensive effort to accelerate the adoption of plug-in electric vehicles (PEVs). The team proposes the creation of a pre-sale education and awareness program, PEV sales and leasing facilitation, post-sale customer service and a network of charging stations throughout the Southeast. This vision includes the establishment of strategic concierge locations for hands-on driving experiences and the opportunity to purchase PEVs through a network of dealer partners.

Team Members:

Bryan Coley (Gulf; pictured), John Socha (SCS; pictured), Blair Farley (SCS), Trey Hayes (APC), John Peters (GPC), Jamie Sandford (APC), Lincoln Wood (SCS)

Delivers Long-Term Shareholder Value

Customer-Focused Strategy Underpins Consistent Financial Performance

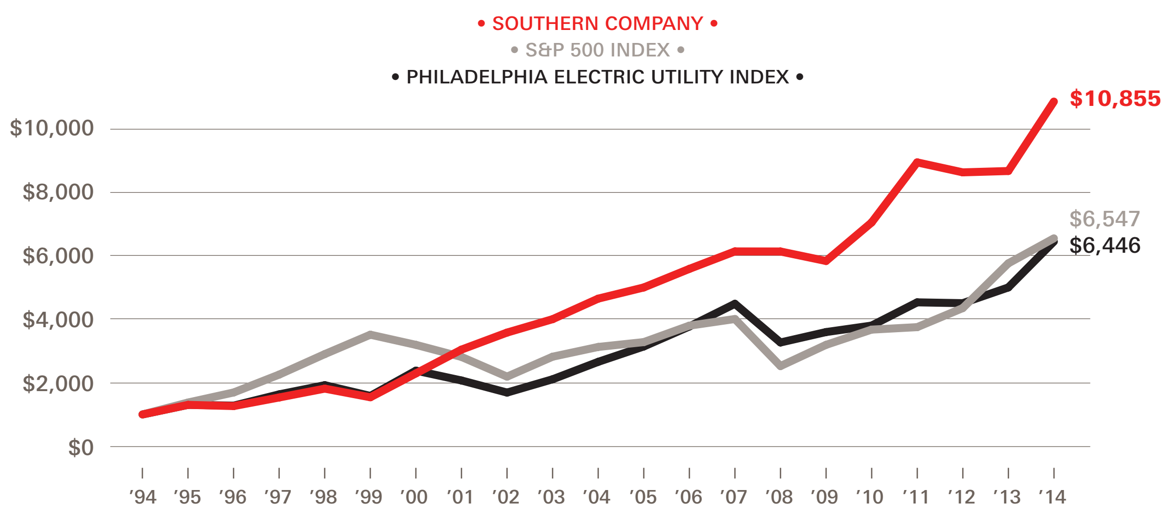
Throughout the 103-year history of Southern Company, customers have remained at the center of all we do. We believe our focus on customers translates to value creation for investors, and this is borne out in the results we have delivered over time.

Over the long term, Southern Company has proved to be an outstanding investment, outperforming the S&P 500 over the 10-, 20- and 30-year periods ending December 31, 2014. Our dividend–an important part of that performance–increased for the 13th consecutive year in 2014, and we have paid shareholder dividends every quarter since 1948. That's 269 consecutive quarters.

At year-end, Southern Company's dividend yield was 4.2 percent, compared with approximately 1.9 percent for the S&P 500. Over the past 20 years, dividends and dividend reinvestment have accounted for approximately 69 percent of the increase in our shareholder value, compared with approximately 37 percent of the increase in shareholder value for the S&P 500.

As we've shared in years past, dividends do more than simply provide cash to shareholders; they help shape a company's approach to risk. Once again, the proof is in the numbers. In 2014, Southern Company was the least volatile stock in the Philadelphia Electric Utility Index. Stocks with low volatility tend to be less prone to price swings during times of market stress, and are therefore considered more stable.

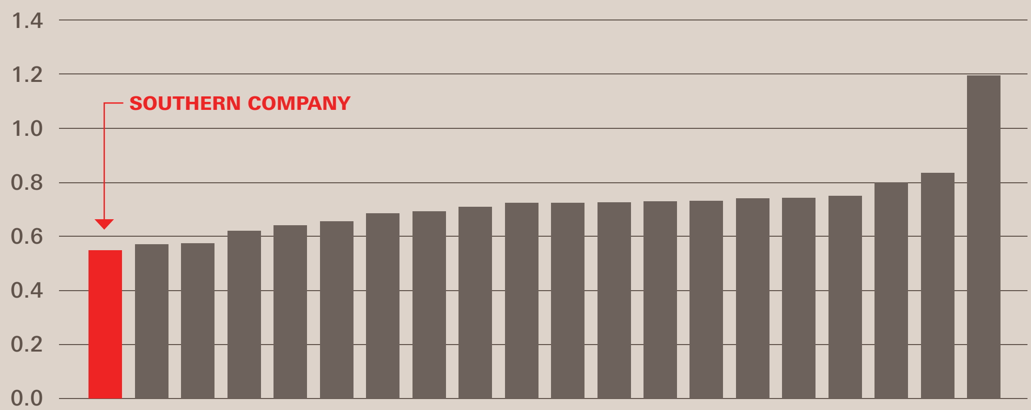
Keeping customers first–along with industry-leading reliability and prices below the national average–has enabled us to sustain operational success, reinforcing our reputation for providing exceptional shareholder value.



Value of $1,000 Invested Over 20 Years

This performance graph compares the cumulative return on Southern Company (SO) common stock with the Philadelphia Electric Utility Index and the Standard & Poor's (S&P) 500 Index for the past 20 years. The average annualized return during the 20-year period is 12.7 percent for Southern Company, compared to 9.8 percent for the UTY and 9.8 percent for the S&P 500. The graph assumes that $1,000 was invested in Southern Company common stock and each of the above indices on December 31, 1994, and that all dividends were reinvested. A five-year performance graph is included in Appendix D to the Proxy Statement.

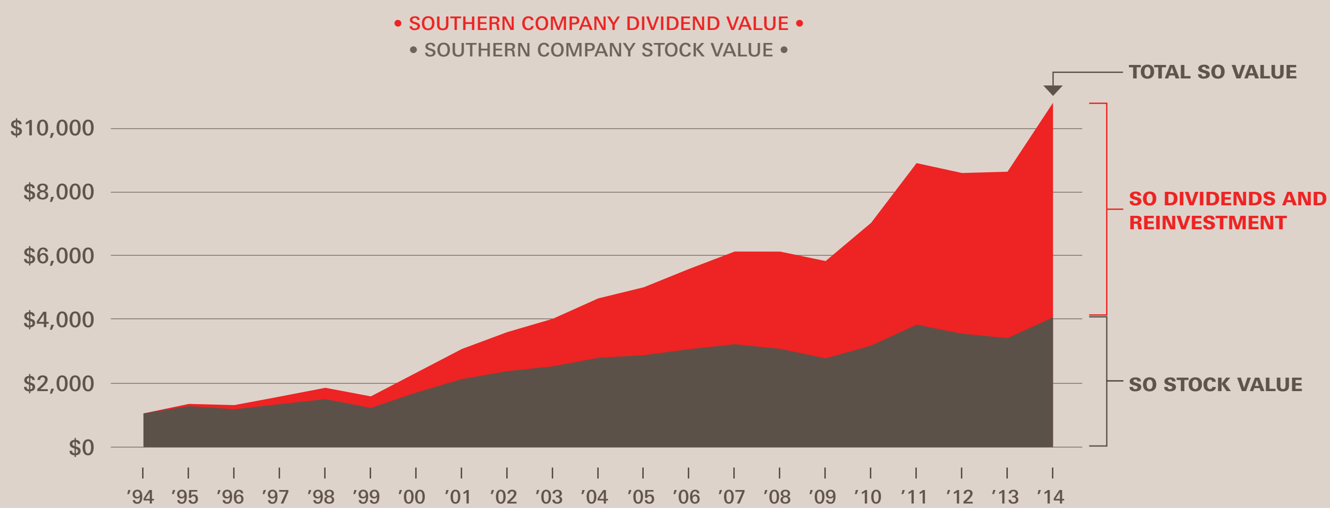
See Glossary on page 36 for information on total shareholder return.
Source: *FactSet and Bloomberg*



Value Added by Low Volatility Relative to the Market

This chart shows the volatility of each of the 20 utilities in the Philadelphia Electric Utility Index (UTY). Volatility refers to the tendency of a stock to react to swings in the market. Southern Company had the lowest level of volatility in the UTY Index and one of lowest in the S&P 500.

See Glossary on page 36 for information on beta.
***Source:** FactSet and Bloomberg, five-year beta as of December 31, 2014*



Value Created by Dividend and Price Performance

This chart shows the power of Southern Company's dividend. Over the last 20 years, a $1,000 investment in SO grew to $10,855. Increases in the value of SO stock contributed $3,047 and dividends, with reinvestment, accounted for an increase of $6,808, or approximately 69 percent of the gain in value. The graph assumes that $1,000 was invested in Southern Company common stock on December 31, 1994, and that all dividends were reinvested.

See Glossary on page 36 for information on total shareholder return.
***Source:** Bloomberg*

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2014 Summary Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning future sources of generation, completion of acquisitions and construction projects and the anticipated benefits thereof, expected retail rates and the potential benefits of possible innovations. 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 Environmental Protection Agency civil actions against certain Southern Company subsidiaries, Federal Enegy Regulatory Commission 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 Public Service Commission);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any Public Service Commission 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 Public Service Commission approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC project, including actions relating to proposed securitization, Mississippi Public Service Commission approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC project to South Mississippi Electric Power Association, 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 Public Service Commission review of the prudence of Kemper IGCC project 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 MPC and the Mississippi Public Service Commission, 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 Department of Energy 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 Southern Company's Annual Report on Form 10-K for the year ended December 31, 2014 (Form 10-K), filed by Southern Company from time to time with the Securities and Exchange Commission.

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

Financial Information

The following condensed financial presentation should not be considered a substitute for the full financial statements, inclusive of footnotes and Management's Discussion and Analysis of Financial Condition and Results of Operations, provided to all shareholders in Appendix D to the Company's 2015 Proxy Statement and included in the Form 10-K as filed with the Securities and Exchange Commission. Appendix D to the Proxy Statement and the Form 10-K also contain detailed discussions of major uncertainties, contingencies, risks, and other issues the Company faces. A copy of the Form 10-K and/or the Proxy Statement, when available, including the full financial statements, can be obtained by calling Shareowner Services at 1-800-554-7626 or by accessing it online at **http://investor.southerncompany.com**.

Management's Report On Internal Control Over Financial Reporting

The management of The 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 appears in Appendix D to the Proxy Statement and in the Form 10-K as filed with the Securities and Exchange Commission.

Thomas A. Fanning

Thomas A. Fanning
Chairman, President and Chief Executive Officer

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 Southern Company

We have audited the consolidated balance sheets and consolidated statements of capitalization of 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 have also audited the effectiveness of the Company's internal control over financial reporting as of December 31, 2014. Such consolidated financial statements, management's assessment of the effectiveness of the Company's internal control over financial reporting, and our report on the consolidated financial statements and internal control over financial reporting dated March 2, 2015, expressing an unqualified opinion (which is not included herein) are included in Appendix D to the proxy statement for the 2015 annual meeting of stockholders. The accompanying condensed consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on such condensed consolidated financial statements in relation to the complete consolidated financial statements.

In our opinion, the information set forth in the accompanying condensed consolidated balance sheets as of December 31, 2014 and 2013, and the related condensed consolidated statements of income and of cash flows for each of the three years in the period ended December 31, 2014, is fairly stated in all material respects in relation to the consolidated financial statements from which it has been derived.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

Condensed Consolidated Statements of Income

For the Years Ended December 31, 2014, 2013, and 2012

(In Millions)	**2014**	2013	2012
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

Full disclosure of all financial information is included in Appendix D to the Proxy Statement and in the Form 10-K as filed with the Securities and Exchange Commission, including the accompanying footnotes, which are an integral part of the financial statements.

Condensed Consolidated Statements of Cash Flows

For the Years Ended December 31, 2014, 2013, and 2012

(In Millions)	**2014**	2013	2012
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

Full disclosure of all financial information is included in Appendix D to the Proxy Statement and in the Form 10-K as filed with the Securities and Exchange Commission, including the accompanying footnotes, which are an integral part of the financial statements.

Condensed Consolidated Balance Sheets

At December 31, 2014 and 2013

Assets *(In Millions)*	2014	2013
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

Full disclosure of all financial information is included in Appendix D to the Proxy Statement and in the Form 10-K as filed with the Securities and Exchange Commission, including the accompanying footnotes, which are an integral part of the financial statements.

Condensed Consolidated Balance Sheets

At December 31, 2014 and 2013

Liabilities and Stockholders' Equity *(In Millions)*	2014	2013
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	**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	**375**	375
Redeemable Noncontrolling Interest	**39**	—
Total Stockholders' Equity	**20,926**	19,764
Total Liabilities and Stockholders' Equity	**$70,923**	$64,546

Full disclosure of all financial information is included in Appendix D to the Proxy Statement and in the Form 10-K as filed with the Securities and Exchange Commission, including the accompanying footnotes, which are an integral part of the financial statements.

Board of Directors

1. **Juanita Powell Baranco**
Executive Vice President and Chief Operating Officer
Baranco Automotive Group (automobile sales)
Atlanta, GA | Age 66 | elected 2006
Board committee: Audit
Other directorships: None

2. **Jon A. Boscia**
Founder and President
Boardroom Advisors LLC
(board governance consulting firm)
Sarasota, FL | Age 62 | elected 2007
Board committee: Audit (chair)
Other directorships: None

3. **Henry A. Clark III**
Senior Advisor
Evercore Partners Inc.
(corporate finance advisory firm)
New York, NY | Age 65 | elected 2009
Board committees: Compensation and Management Succession (chair), Finance
Other directorships: None

4. **Thomas A. Fanning**
Chairman, President and CEO
Southern Company
Atlanta, GA | Age 58 | elected 2010
Other directorships: Federal Reserve Bank of Atlanta, Vulcan Materials Company

5. **David J. Grain**
Founder and Managing Partner
Grain Management, LLC (private equity firm)
Sarasota, FL | Age 52 | elected 2012
Board committees: Compensation and Management Succession, Finance
Other directorship: Gateway Bank of Southwest Florida

6. **Veronica M. Hagen**
Lead Independent Director
Southern Company Board (effective May 2014)
Retired President and CEO
Polymer Group, Inc. (engineered materials)
Charlotte, NC | Age 69 | elected 2008
Board committees: Compensation and Management Succession, Nuclear/Operations
Other directorships: Polymer Group, Inc., Newmont Mining Corporation

7. **Warren A. Hood, Jr.**
Chairman and CEO
Hood Companies, Inc.
(packaging and construction products)
Hattiesburg, MS | Age 63 | elected 2007
Board committee: Audit
Other directorships: Hood Companies, Inc., BancorpSouth, Inc.

8. Linda P. Hudson
Founder, Chairman and CEO
The Cardea Group
(business management consulting)
Charlotte, NC | Age 64 | elected 2014
Board committees: Governance, Nuclear/Operations, Business Security Subcommittee
Other directorships: BAE Systems, Inc., Bank of America Corporation

9. Donald M. James
Chairman and Retired CEO
Vulcan Materials Company
(construction materials)
Birmingham, AL | Age 66 | elected 1999
Board committees: Governance (chair), Finance
Other directorships: Vulcan Materials Company, Wells Fargo & Company

10. John D. Johns
Chairman, President and CEO
Protective Life Corporation
(insurance)
Birmingham, AL | Age 63 | elected 2015
Board committee: Audit
Other directorships: Protective Life Corporation, Regions Financial Corporation, Genuine Parts Company

11. Dale E. Klein
Associate Vice Chancellor of Research
University of Texas System
Associate Director The Energy Institute at the University of Texas at Austin
Retired Chairman U.S. Nuclear Regulatory Commission (energy)
Austin, TX | Age 67 | elected 2010
Board committees: Governance, Nuclear/Operations, Business Security Subcommittee (chair)
Other directorships: Pinnacle West Capital Corporation, Arizona Public Service Company

12. William G. Smith, Jr.
Chairman, President and CEO
Capital City Bank Group, Inc. (banking)
Tallahassee, FL | Age 61 | elected 2006
Board committees: Compensation and Management Succession, Finance (chair)
Other directorships: Capital City Bank Group, Inc., Capital City Bank

13. Steven R. Specker
Retired President and CEO
Electric Power Research Institute (energy)
Scottsdale, AZ | Age 69 | elected 2010
Board committees: Nuclear/Operations (chair), Compensation and Management Succession
Other directorship: Trilliant, Inc.

14. Larry D. Thompson
Retired Executive Vice President
PepsiCo, Inc. (food and beverage products)
Atlanta, GA | Age 69 | elected 2014
Board committee: Audit
Other directorships: Graham Holdings Company, Franklin, Templeton Series Mutual Funds

15. E. Jenner Wood III
Chairman and CEO
SunTrust Bank–Atlanta Division (banking)
Atlanta, GA | Age 63 | elected 2012
Board committees: Governance, Nuclear/Operations
Other directorships: Oxford Industries, Inc., Genuine Parts Company

Management Council

1. Art P. Beattie
Executive Vice President and Chief Financial Officer

Beattie, 60, joined the company in 1976 as a junior accountant with Alabama Power. He has held his current position since August 2010. Beattie is responsible for the company's accounting, finance, tax, investor relations, treasury and risk management functions. He also serves as chief risk officer. Previously, Beattie served in several executive accounting and finance positions at Alabama Power, including chief financial officer, treasurer and comptroller.

2. W. Paul Bowers
Executive Vice President
Chairman, President and CEO, Georgia Power

Bowers, 58, joined the company as a residential sales representative with Gulf Power in 1979. He has held his current position since January 2011. Previously, Bowers served as chief financial officer for Southern Company. He also served as president of Southern Company Generation, president and CEO of Southern Power, president and CEO of Southern Company's former United Kingdom subsidiary and senior vice president and chief marketing officer for Southern Company.

3. Stan W. Connally, Jr.
President and CEO, Gulf Power

Connally, 45, joined the company in 1989 as a co-op student at Georgia Power. He has held his current position since July 2012. Previously, he served as senior vice president and senior production officer for Georgia Power. He has served as plant manager at plants Watson, Daniel and Barry. He has also worked in customer operations and sales and marketing.

4. Mark A. Crosswhite
Executive Vice President
Chairman, President and CEO, Alabama Power

Crosswhite, 52, joined the company in 2004 as senior vice president and general counsel for Southern Company Generation. He has held his current position since March 2014. He was previously executive vice president and chief operating officer for Southern Company, president and CEO of Gulf Power and executive vice president of external affairs and senior vice president and general counsel at Alabama Power. Prior to joining the company, he was a partner in the law firm of Balch & Bingham LLP in Birmingham, Alabama, where he practiced for 17 years.

5. Thomas A. Fanning
Chairman, President and CEO

Fanning, 58, joined the company as a financial analyst in 1980. He has held his current position since December 2010. Previously, Fanning served as executive vice president and chief operating officer for Southern Company, president and CEO of Gulf Power and chief financial officer for Southern Company, Georgia Power and Mississippi Power.

6. Kimberly S. Greene
Executive Vice President and
Chief Operating Officer

Greene, 48, has held her current role since March 2014. Previously, she was president and CEO of Southern Company Services. Prior to that, she was employed by TVA, where she served as chief financial officer, group president of strategy and external relations and chief generation officer. Prior to her time at TVA, she served as senior vice president of finance and treasurer for Southern Company and has held various positions with Mirant, including chief commercial officer, South Region.

7. G. Edison Holland, Jr.
Executive Vice President
Chairman, President and CEO, Mississippi Power

Holland, 62, joined the company as vice president and corporate counsel for Gulf Power in 1992. He was named to his current position in May 2013. Previously, he was executive vice president, general counsel and corporate secretary of Southern Company, president and CEO of Savannah Electric and vice president of power generation and transmission at Gulf Power.

8. James Y. Kerr II
Executive Vice President and General Counsel

Kerr, 51, assumed his current role in March 2014. Previously, he was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC. He also served as co-chairman of McGuireWoods' energy industry team with focus in the areas of energy transactions and finance, energy regulation, energy policy and energy litigation. Prior to joining McGuireWoods, Kerr served as a Commissioner on the North Carolina Utilities Commission and was the former president of the National Association of Regulatory Utility Commissioners.

9. Stephen E. Kuczynski
Chairman, President and CEO, Southern Nuclear

Kuczynski, 52, joined the company in July 2011 as chairman, president and CEO of Southern Nuclear. Previously, he was senior vice president of engineering and technical services for Exelon Nuclear. He also served as senior vice president of Exelon Nuclear's Midwest operations, senior vice president of operations support and plant manager and later site vice president of Exelon's Byron Nuclear Station.

10. Mark S. Lantrip
Executive Vice President
Chairman, President and CEO,
Southern Company Services, Inc.

Lantrip, 60, joined the company in 1981 as an analyst in Gulf Power's corporate planning department. He assumed his current position in March 2014. Previously, Lantrip was executive vice president of finance and treasurer of Southern Company Services and treasurer of Southern Company, with responsibility for financial planning and analysis, enterprise risk management, trust finance, capital markets and treasury.

11. Christopher C. Womack
Executive Vice President and President
of External Affairs

Womack, 57, joined the company in 1988 as a governmental affairs representative for Alabama Power. He has held his current position since January 2009. Previously, Womack was executive vice president of external affairs for Georgia Power. He has also served as senior vice president of human resources and chief people officer for Southern Company as well as senior vice president and senior production officer of Southern Company Generation.

APC
Abbreviation for Alabama Power Company.

Basic Earnings Per Share Excluding Kemper IGCC Impacts, Leveraged Lease Restructure Charge, And MC Asset Recovery Insurance Settlements
Basic earnings per share in 2014 of $2.19 plus an excluded 59-cent charge related to Mississippi Power's construction of the Kemper integrated gasification combined cycle project and plus an excluded 2-cents related 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 Public Service Commission's March 2013 rate order related to the Kemper IGCC project; basic earnings per share in 2013 of $1.88 plus an excluded 83-cent charge related to Mississippi Power's construction of the Kemper IGCC project, plus an excluded 2-cent charge related to the restructuring of a leveraged lease investment, and minus an excluded MC Asset Recovery insurance settlement of 2 cents; and basic earnings per share in 2012 of $2.70 minus an excluded MC Asset Recovery insurance settlement of 2 cents.

Beta
A measure of the volatility of a stock in comparison to the market as a whole. Beta can be described as the tendency of a security's returns to respond to swings in the market.

Book Value
A company's common stock equity as it appears on a balance sheet, equal to total assets minus liabilities, preferred and preference stock and intangible assets such as good will. Book value per share refers to the book value of a company divided by the number of shares outstanding.

CO_2
Abbreviation for carbon dioxide.

Coal Gasification
A process in which the energy stored in coal is converted to gas, making it available for use in refineries for the synthesis of chemicals or in gas-fired power plants as a fuel.

Desalination
The process of removing salt, especially from sea water, so that it can be used for drinking or irrigation.

Diluted Earnings Per Share
A company's earnings per share calculated by using fully diluted shares outstanding, including the impact of stock option grants and convertible bonds that can be converted into shares of stock in the issuing company.

Dividend Yield
The annual dividend income per share received from a company divided by its current stock price.

Earnings Per Share
Net income divided by the average number of shares of common stock outstanding.

Energy Audit
An onsite inspection in which recommendations are made for improving the energy efficiency of a home or business.

GPC
Abbreviation for Georgia Power Company.

Gulf
Abbreviation for Gulf Power Company.

Integrated Gasification Combined Cycle (IGCC)
A technology that uses a gasifier to turn coal and other carbon-based fuels into synthesis gas (syngas). It then removes impurities from the syngas before it is combusted. This results in lower emissions of sulfur dioxide, particulates and mercury.

HVAC
Abbreviation for heating, ventilation and air conditioning.

Kilowatt-Hour
A unit of electricity equal to 1,000 watt-hours, delivered by an electric utility steadily for one hour.

LED (Light-Emitting Diodes)
Semiconductor devices that produce visible light when an electrical current is passed through them. LED lighting can be more efficient, durable and longer lasting.

Megawatt
A measurement of electricity equal to 1,000 kilowatts and typically used when describing large amounts of generating capacity.

mmBtu
Abbreviation for Million British thermal units.

MPC
Abbreviation for Mississippi Power Company.

Proton-Exchange Membrane Fuel Cell Vehicles
Vehicles that are powered by proton exchange membrane fuel cells, a type of fuel cell being developed for transport applications as well as for stationary and portable fuel cell applications.

Reliability
As pertains to electric networks, the extent to which supply is available to meet demand.

Renewable Energy
Energy generated directly from natural resources such as sunlight, wind, water, biomass, ocean tides and geothermal heat.

SCS
Abbreviation for Southern Company Services, Inc.

System Average Interruption Frequency Index (SAIFI)
SAIFI is the average number of times that a system customer experiences an outage during a year (or some particular time period under study). The SAIFI is found by dividing the total number of customers interrupted by the total number of customers served.

Total Shareholder Return
Stock Price appreciation plus reinvested dividends. (The distribution of shares of Mirant Corporation stock to Southern Company shareholders is treated as a special dividend for the purposes of calculating Southern Company shareholder return.)

TVA
Abbreviation for Tennessee Valley Authority.

Shareholder Information

Transfer Agent
Computershare, Inc. is Southern Company's transfer agent, dividend-paying agent, investment plan administrator and registrar. If you have questions concerning your registered Southern Company shareowner account, please contact:

By Mail
Computershare
P.O. Box 30170
College Station, TX 77842-3170

By Courier
Computershare
211 Quality Circle
Suite 210
College Station, TX 77845

By Phone-U.S.
9 a.m. to 7 p.m. ET
Monday through Friday
800-554-7626
(Automated voice response system
24 hours/day, 7 days/week)
Hearing Impaired: 800-231-5469

By Phone-Outside U.S.
201-680-6693

Shareowner Services Internet Site
To take advantage of Shareowner Services' online services, you will need to activate your account. This one-time authentication process will be used to validate your identity. You can use your 12-digit Investor ID or your Computershare Holder ID. The Internet address is www.computershare.com/investor. Through this site, registered shareowners can securely access their account information, as well as submit numerous transactions. Also, transfer instructions and service request forms can be obtained.

Southern Investment Plan
The Southern Investment Plan provides a convenient way to purchase common stock and reinvest dividends. You can access the Southern Company website to review the prospectus.

Direct Registration
Southern Company common stock can be issued in direct registration (uncertificated) form. The stock is Direct Registration System eligible.

Dividend Payments
The entire amount of dividends paid in 2014 is taxable. The board of directors sets the record and payment dates for quarterly dividends. A dividend of 52.5 cents per share was paid in March 2015. For the remainder of 2015, projected record dates are May 18, August 17 and November 16. Projected payment dates for dividends declared during the remainder of 2015 are June 6, September 5 and December 5.

Annual Meeting
The 2015 Annual Meeting of Stockholders will be held Wednesday, May 27, at 10 a.m. ET at The Lodge Conference Center at Callaway Gardens, Highway 18, Pine Mountain, Ga. 31822.

Auditors
Deloitte & Touche, LLP
191 Peachtree St. NE
Suite 2000
Atlanta, GA 30303

Investor Information
For information about earnings and dividends, stock quotes and current news releases, please visit us at www.investor.southerncompany.com.

Institutional Investor Inquiries
Southern Company maintains an investor relations office in Atlanta, 404-506-5310, to meet the information needs of institutional investors and securities analysts.

Electronic Delivery Of Proxy Materials
Any stockholder may enroll for electronic delivery of proxy materials by logging on at www.icsdelivery.com/so.

Certifications
Southern Company has filed the required certifications of its chief executive officer and chief financial officer under Section 302 of the Sarbanes-Oxley Act of 2002, regarding the quality of its public disclosures as exhibits 31(a)1 and 31(a)2, respectively, to Southern Company's Annual Report on Form 10-K for the year ended December 31, 2014. The certification of Southern Company's chief executive officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards, required by NYSE Rule 303A.12, will be filed with the NYSE following the 2015 Annual Meeting of Stockholders. Last year, Southern Company filed this certification with the NYSE on June 14, 2014.

Environmental Information
Southern Company publishes information on its activities to meet environmental commitments. This information is available online at www.southerncompany.com/planetpower/#reports.

To request printed materials, write to:
Larry Monroe
Chief Environmental Officer & Senior Vice President
Research and Environmental Affairs
600 North 18th St.
Bin 14N-8195
Birmingham, AL 35203-2206

Common Stock
Southern Company common stock is listed on the NYSE under the ticker symbol SO. On December 31, 2014, Southern Company had 137,369 shareholders of record.

The 2014 summary annual report is submitted for shareholders' information. It is not intended for use in connection with any sale or purchase of, or any solicitation of, offers to buy or sell securities.

Visit our website at www.southerncompany.com

Visit our Corporate Responsibility Report at www.southerncompany.com/corporateresponsibility

Follow us on Twitter at www.twitter.com/southerncompany

MIX
Paper from responsible sources
FSC® C017228
www.fsc.org

Writing & Project Management: Terrell McCollum. **Financial Review:** Laura Carden. **Design:** Leap Communications. **Major Photography:** James Schnepf and Philip Wages. **Printing:** American Printing Co.

SOUTHERN COMPANY

SOUTHERNCOMPANY.COM

Exhibit 7

SOUTHERN COMPANY

NOTICE OF 2015 ANNUAL MEETING OF STOCKHOLDERS, PROXY STATEMENT AND 2014 ANNUAL REPORT

TABLE OF CONTENTS

* To be voted on at the meeting.

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

Dear Fellow Stockholder:

You are invited to attend the 2015 Annual Meeting of Stockholders at 10 a.m. ET on Wednesday, May 27, 2015, at The Lodge Conference Center at Callaway Gardens, Pine Mountain, Georgia.

Your vote is important. Whether or not you plan to attend the meeting, please review the proxy material and vote by internet, phone, or mail as soon as possible.

At the annual meeting, I will report on our accomplishments from 2014, as well as our plans for 2015 and beyond. We will also elect our Board of Directors and vote on the other matters described in this Proxy Statement.

Throughout the entire 103-year history of The Southern Company, customers have always been at the center of all we do. This customer-focused business model continues to inform the decisions we make as we consider how our actions will potentially benefit the families, businesses, and communities we serve. Going forward, we will remain grounded in this core value.

This Proxy Statement includes Appendix D, the 2014 Annual Report with The Southern Company's audited financial statements and management's discussion and analysis of results of operation and financial condition.

We look forward to seeing you on May 27th. Thank you for your continued support of The Southern Company.

Thomas A. Fanning

Thomas A. Fanning

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS OF THE SOUTHERN COMPANY

DATE: Wednesday, May 27, 2015

TIME: 10:00 a.m., ET

PLACE: The Lodge Conference Center at Callaway Gardens
Highway 18
Pine Mountain, Georgia 31822

DIRECTIONS: ***From Atlanta, Georgia*** — Take I-85 south to I-185 (Exit 21). From I-185 south, take Exit 34, Georgia Highway 18. Take Georgia Highway 18 east to Callaway.

From Birmingham, Alabama — Take U.S. Highway 280 east to Opelika. Take I-85 north to Georgia Highway 18 (Exit 2). Take Georgia Highway 18 east to Callaway.

Items of Business

1. To elect 15 Directors;

2. To approve The Southern Company Outside Directors Stock Plan;

3. To approve an amendment to the By-Laws related to the ability of stockholders to act by written consent to amend the By-Laws;

4. To approve on a non-binding advisory basis The Southern Company's named executive officers' compensation;

5. To ratify the appointment of Deloitte & Touche LLP as The Southern Company's independent registered public accounting firm for 2015;

6. To consider a stockholder proposal on proxy access;

7. To consider a stockholder proposal on greenhouse gas emissions reduction goals; and

8. To transact any other business properly coming before the meeting or any adjournments thereof.

Record Date

Stockholders of record at the close of business on March 30, 2015 are entitled to attend and vote at the meeting. On that date, there were 908,996,758 shares of common stock (Common Stock) of The Southern Company (Southern Company or the Company) outstanding and entitled to vote.

Annual Report to Stockholders

Appendix D to this Proxy Statement is The Southern Company's 2014 Annual Report.

By Order of the Board of Directors,
Melissa K. Caen, Corporate Secretary,
April 10, 2015

VOTING INFORMATION

Even if you plan to attend the meeting in person, please provide your voting instructions as soon as possible by internet, by phone using the toll-free number, or by mail by marking, signing, dating, and returning the proxy form in the enclosed, postage-paid envelope.

Voting by the internet or by phone is fast and convenient, and your vote is immediately confirmed and tabulated.

PROXY VOTING OPTIONS

YOUR VOTE IS IMPORTANT!

Voting early will ensure the presence of a quorum at the meeting and may save The Southern Company the expense and extra work of additional solicitation.

VOTE BY INTERNET

www.proxyvote.com
24 hours a day/7 days a week
Instructions:
Read this Proxy Statement
Go to the following website:
www.proxyvote.com
Have your proxy form or voting instruction form in hand and follow the instructions.

VOTE BY PHONE

1-800-690-6903
Toll-free 24 hours a day/7 days a week
Instructions:
Read this Proxy Statement

Have your proxy form or voting instruction form in hand and follow the instructions.

Please do not return the enclosed paper ballot if you are voting by internet or phone.

Important Notice Regarding the Availability of Proxy Materials for the 2015 Annual Meeting of Stockholders to be held on May 27, 2015:

The Company's 2015 Proxy Statement, which includes the 2014 Annual Report as an appendix, is also available free of charge on the Company's website at http://investor.southerncompany.com/proxy.

The Company's 2014 Annual Report filed with the Securities and Exchange Commission (SEC) on Form 10-K will be provided without charge upon written request to Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

PROXY SUMMARY

This summary highlights information contained elsewhere in this Proxy Statement. This summary does not contain all of the information that you should consider, and you should read the entire Proxy Statement carefully before voting.

Meeting Agenda

Stockholders are being asked to vote on the following matters at the 2015 Annual Meeting of Stockholders (2015 Annual Meeting):

	The Board's Recommendation
Item 1. Election of 15 Directors (page 1) Each nominee holds or has held senior executive positions, maintains the highest degree of integrity and ethical standards, and complements the needs of the Company. Through their positions, responsibilities, skills, and perspectives, which span various industries and organizations, these nominees represent a Board that is diverse and possesses appropriate collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and the Company's industry and subsidiaries' service territories.	For each Director nominee
Item 2. Approve The Southern Company Outside Directors Stock Plan (page 9) The Board of Directors has adopted effective June 1, 2015, subject to stockholder approval, the Outside Directors Stock Plan for Directors of The Southern Company and its Subsidiaries. The purpose of the Outside Directors Stock Plan is to provide a mechanism for non-employee Directors to automatically increase their ownership of Common Stock and thereby further align their interests with those of the Company's stockholders.	For
Item 3. Approve Amendment to the By-Laws Related to the Ability of Stockholders to Act by Written Consent to Amend the By-Laws (page 9) The Board of Directors has determined that it is in the best interests of the Company and its stockholders to amend the Company's By-Laws to permit stockholders to take action to amend the By-Laws without a meeting by the written consent of holders of not less than the minimum number of the issued and outstanding shares that would be necessary to take such action at a meeting at which all shares entitled to vote thereon were present and voted.	For
Item 4. Advisory Vote on Named Executive Officers' Compensation (page 24) The Company believes its compensation program provides the appropriate mix of fixed and short- and long-term performance-based compensation that rewards achievement of the Company's financial success, business unit financial and operational success, and total shareholder return. The Company seeks a non-binding advisory vote from its stockholders to approve the compensation of its named executive officers.	For
Item 5. Ratification of Independent Auditor for 2015 (page 71) The Audit Committee has appointed Deloitte & Touche LLP (Deloitte & Touche) as the Company's independent registered public accounting firm for 2015. This appointment is being submitted to stockholders for ratification, and the Audit Committee and the Board of Directors believe that the continued retention of Deloitte & Touche to serve as the Company's independent registered public accounting firm is in the best interests of the Company and its stockholders.	For
Item 6. Stockholder Proposal on Proxy Access, if properly presented (page 73) Proxy access is an untested governance feature for U.S. companies and it should not be implemented in the absence of a compelling rationale. The proponent's proxy access proposal does not seek to remedy any specific governance or performance deficiency at the Company. The Company already has significant corporate governance practices that protect stockholder rights and interests. Implementing proxy access on the terms of this proposal could negatively affect the Company's corporate governance.	Against
Item 7. Stockholder Proposal on Greenhouse Gas Emissions Reduction Goals, if properly presented (page 76) The Board of Directors does not believe it is in the best interests of the Company or its stockholders to independently establish at this time voluntary, absolute quantitative goals for reducing total greenhouse gas emissions from the Southern Company system's operations. A separate report as requested in the proposal regarding plans to achieve such goals would not be an efficient use of additional Company resources or add value to the Company's current efforts in this area.	Against

Questions and Answers About the 2015 Annual Meeting

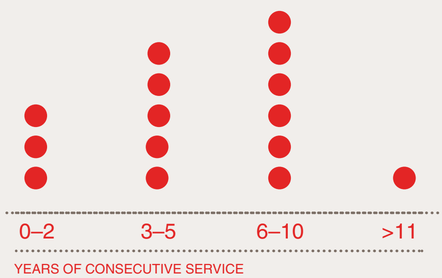
Please review "Frequently Asked Questions" on page 79 for answers to common questions about the 2015 Annual Meeting.

Key Corporate Governance Features

Southern Company seeks to establish corporate governance standards and practices that will be of value to long-term stockholders and create positive influences in the governance of the Company. Several of our key governance standards and practices include:

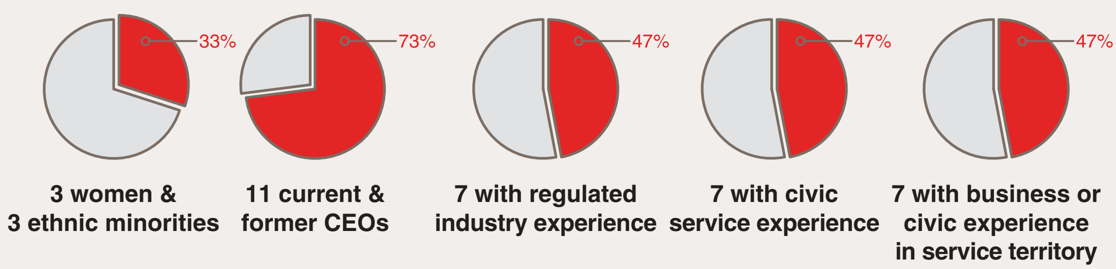
- Annual election of Directors
- Majority voting for Directors, with a Director resignation policy
- 10% threshold for stockholders to request a special meeting
- 14 of 15 Directors are independent
- Strong Lead Independent Director
- Annual Board and committee self-evaluations
- Proactive stockholder engagement

BOARD TENURE IN YEARS



INDEPENDENCE

BOARD DIVERSITY



Recent Governance Enhancements

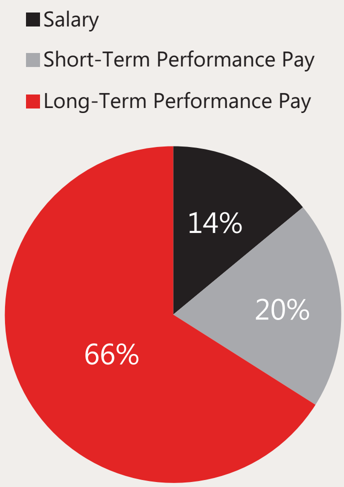
- Established Business Security Subcommittee of the Board...see page 20
- Increased Stakeholder Engagement Efforts...see page 12
- Added Former U.S. Deputy Attorney General Larry D. Thompson to the Board...see page 8
- Added Alabama Business and Civic Leader John D. Johns to the Board...see page 6
- Enhanced the Responsibilities of the Lead Independent Director...see page 15
- Refreshed the Composition of Key Board Committees...see pages 16 to 20

Executive Compensation Summary

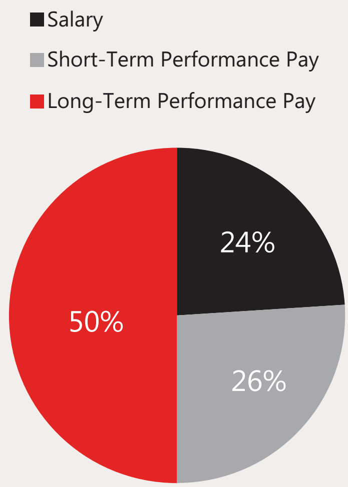
Performance and Pay

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2014.

Chief Executive Officer (1)



Other Named Executive Officers (1)



(1) Salary is the actual amount paid in 2014, Short-Term Performance Pay is the actual amount earned in 2014 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2014. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in the Compensation Discussion and Analysis. Information is provided for named executive officers serving at the end of 2014.

Compensation and Benefit Beliefs and Practices

The Company's compensation and benefit program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that the Company's executive compensation program should:

- Be competitive with the Company's industry peers;
- Motivate and reward achievement of the Company's goals;
- Be aligned with the interests of the Company's stockholders and its subsidiaries' customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of the Company's business goals. The Company believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for the Company's stockholders. Therefore, short-term performance pay is based on achievement of the Company's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by Company earnings per share performance. Long-term performance pay is tied to stockholder value, with 40% of the target value awarded in stock options, which reward stock price appreciation, and 60% awarded in performance shares, which reward total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Compensation Practices

WHAT WE DO

Annual pay risk assessment

Independent compensation consultant

Claw-back provision

Strong stock ownership requirements

WHAT WE DON'T DO

"No-hedging" provision in insider trading policy

No excise tax gross-ups on change-in-control severance arrangements

Limited ongoing perquisites

Item No. 1 — Election of Directors

Nominees for Election as Directors

The Proxies named on the proxy form will vote, unless otherwise instructed, each properly executed proxy form for the election of the following nominees as Directors. If any named nominee becomes unavailable for election, the Board may substitute another nominee. In that event, the proxy would be voted for the substitute nominee unless instructed otherwise on the proxy form. Each nominee, if elected, will serve until the 2016 Annual Meeting of Stockholders.

The Board of Directors, acting upon the recommendation of the Governance Committee, nominates the following individuals for election to the Southern Company Board of Directors. Each nominee holds or has held senior executive positions, maintains the highest degree of integrity and ethical standards, and complements the needs of the Company. Through their positions, responsibilities, skills, and perspectives, which span various industries and organizations, these nominees represent a Board that is diverse and possesses appropriate collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and the Company's industry and subsidiaries' service territories, as detailed below.

Juanita Powell Baranco

Age: 66

Director since: 2006

Board committee: Audit

Principal occupation: Executive Vice President and Chief Operating Officer of Baranco Automotive Group, automobile sales

Other public company directorships: None (formerly a Director of Cox Radio, Inc. and Georgia Power Company)

Director biography: Ms. Baranco had a successful legal career, which included serving as Assistant Attorney General for the State of Georgia, before she and her husband founded the first Baranco dealership in Atlanta in 1978. She served as a Director of Georgia Power Company (Georgia Power), the largest subsidiary of the Company, from 1997 to 2006. During her tenure on the Georgia Power Board, she was a member of the Controls and Compliance, Diversity, Executive, and Nuclear Operations Overview Committees. She served on the Federal Reserve Bank of Atlanta Board for a number of years and also on the Boards of Directors of John H. Harland Company and Cox Radio, Inc. An active leader in the Atlanta community, she serves on the Board of Trustees for Clark Atlanta University and on the Advisory Council for the Catholic Foundation of North Georgia, the Commerce Club, and the Woodruff Arts Center. She is also past Chair of the Board of Regents for the University System of Georgia and past Board Chair for the Sickle Cell Foundation of Georgia.

The Board has benefited from Ms. Baranco's particular expertise in business operations and her civic involvement.

Jon A. Boscia

Age: 62

Director since: 2007

Board committee: Audit (Chair)

Principal occupation: Founder and President, Boardroom Advisors LLC, board governance consulting firm

Other public company directorships: None (formerly a Director of PHH Corporation, Sun Life Financial Inc., Armstrong World Industries, Lincoln Financial Group, Georgia Pacific Corporation, and The Hershey Company)

Director biography: From September 2008 until March 2011, Mr. Boscia served as President of Sun Life Financial Inc. In this capacity, Mr. Boscia managed a portfolio of the company's operations with ultimate responsibility for the United States, United Kingdom, and Asia business groups and directed the global marketing and investment management functions. Previously, Mr. Boscia served as Chairman of the Board and Chief Executive Officer of Lincoln Financial Group, a diversified financial services organization, until his retirement in 2007. Mr. Boscia became the Chief Executive Officer of Lincoln Financial Group in 1998. During his time at Lincoln Financial Group, the company earned a reputation for its stellar performance in making major acquisitions. Mr. Boscia is a past member of the Board of PHH Corporation, where he was Chair of the Audit Committee and a member of the Regulatory Oversight Committee, past member of the Board of Sun Life Financial Inc., where he was a member of the Investment Oversight Committee and the Risk Review Committee, and past member of the Board of The Hershey Company, where he chaired the Corporate Governance Committee and served on the Executive Committee. In addition, Mr. Boscia has served in leadership positions on other public company boards as well as not-for-profit and industry boards.

Mr. Boscia's extensive background in finance, investment management, information technology, and corporate governance are valuable to the Board.

Henry A. "Hal" Clark III

Age: 65

Director since: 2009

Board committees: Compensation and Management Succession (Chair), Finance

Principal occupation: Senior Advisor of Evercore Partners Inc. (formerly Lexicon Partners, LLC), corporate finance advisory firm, since July 2009

Other public company directorships: None

Director biography: As a Senior Advisor with Evercore Partners Inc. (formerly Lexicon Partners, LLC), Mr. Clark is primarily focused on expanding advisory activities in North America with a particular focus on the power and utilities sectors. With more than 30 years of experience in the global financial and the utility industries, Mr. Clark brings a wealth of experience in finance and risk management to his role as a Director. Prior to joining Evercore Partners Inc., Mr. Clark was Group Chairman of Global Power and Utilities at Citigroup, Inc. from 2001 to 2009. His work experience includes numerous capital markets transactions of debt, equity, bank loans, convertible securities, and securitization, as well as advice in connection with mergers and acquisitions. He also has served as policy advisor to numerous clients on capital structure, cost of capital, dividend strategies, and various financing strategies. He has served as Chair of the Wall Street Advisory Group of the Edison Electric Institute.

Mr. Clark's utility global financial and utility industry expertise as well as his expertise in capital market transactions are valuable to the Board.

Thomas A. Fanning

Age: 58
Director since: 2010
Principal occupation: Chairman of the Board, President, and Chief Executive Officer of the Company since December 2010
Other public company directorships: Vulcan Materials Company

Director biography: Mr. Fanning has held numerous leadership positions across the Southern Company system during his more than 30 years with the Company. He served as Executive Vice President and Chief Operating Officer of the Company from 2008 to 2010, leading the Company's generation and transmission, engineering, and construction services, research and environmental affairs, system planning, and competitive generation business units. He served as the Company's Executive Vice President and Chief Financial Officer from 2007 to 2008 and Executive Vice President, Chief Financial Officer, and Treasurer from 2003 to 2007, where he was responsible for the Company's accounting, finance, tax, investor relations, treasury, and risk management functions. In those roles, he also served as the chief risk officer and had responsibility for corporate strategy. Mr. Fanning is on the Board of Southern Power Company (Southern Power), a subsidiary of Southern Company. Mr. Fanning is also a Director of Vulcan Materials Company, serving as a member of the Audit Committee and the Compensation Committee, and the Federal Reserve Bank of Atlanta, serving as Chairman of the Board. Mr. Fanning served on the Board of The St. Joe Company from 2005 through September 2011.

Mr. Fanning's knowledge of the Company's business and the electric utility industry, understanding of the complex regulatory structure of the industry, and experience in strategy development and execution uniquely qualify him to be the Chairman of the Board.

David J. Grain

Age: 52
Director since: 2012
Board committees: Compensation and Management Succession, Finance
Principal occupation: Founder and Managing Partner, Grain Management, LLC, private equity firm
Other public company directorships: None

Director biography: Mr. Grain is the founding member and managing partner of Grain Management LLC (Grain Management), a private equity firm focused on investments in the media and communications sectors, which he founded in 2006. With offices in Sarasota, Florida and Washington, D.C., the firm manages funds for a number of the country's leading academic institutions, endowments, and public pension funds. Grain Management also builds, owns, and operates wireless infrastructure assets across North America. Mr. Grain also founded and was Chief Executive Officer of Grain Communications Group, Inc. Prior to Grain Management, he served as President of Global Signal, Inc., Senior Vice President of AT&T Broadband's New England Region, and Executive Director in the High Yield Finance Department at Morgan Stanley. Mr. Grain was appointed by President Obama in 2011 to the National Infrastructure Advisory Council. He previously served as chairman of the Florida State Board of Administration Investment Advisory Council as an appointee of the former Governor Charlie Crist. He is currently a Director at Gateway Bank of Southwest Florida, a Trustee of the College of the Holy Cross, and serves on the Investment Committee of the United States Tennis Association.

Mr. Grain's background in finance, investment management, and wireless communications infrastructure, leadership, and civic involvement are valuable to the Board.

Veronica M. Hagen

Age: 69

Director since: 2008; Lead Independent Director since May 28, 2014

Board committees: Compensation and Management Succession, Nuclear/Operations

Other public company directorships: Polymer Group, Inc., Newmont Mining Corporation

Director biography: From 2007 until her retirement in 2013, Ms. Hagen served as Chief Executive Officer of Polymer Group, Inc., where she continues to serve as a Director and Chair of the Nominating and Corporate Governance Committee. Ms. Hagen also served as President of Polymer Group, Inc. from January 2011 until her retirement in 2013. Polymer Group, Inc. is a leading producer and marketer of engineered materials. Prior to joining Polymer Group, Inc., Ms. Hagen was the President and Chief Executive Officer of Sappi Fine Paper, a division of Sappi Limited, the South African-based global leader in the pulp and paper industry, from November 2004 until 2007. She also has served as Vice President and Chief Customer Officer at Alcoa Inc. and owned and operated Metal Sales Associates, a privately-held metal business. Ms. Hagen also serves as the Chair of the Compensation Committee and a member of the Environmental, Social Responsibility, and Safety Committee of the Board of Newmont Mining Corporation.

Ms. Hagen's global operational management experience and commercial business leadership are valuable assets to the Board.

Warren A. Hood, Jr.

Age: 63

Director since: 2007

Board committee: Audit

Principal occupation: Chairman of the Board and Chief Executive Officer of Hood Companies, Inc., packaging and construction products

Other public company directorships: BancorpSouth, Inc. (formerly a Director of Mississippi Power Company)

Director biography: Mr. Hood is the Chairman and Chief Executive Officer of Hood Companies Inc. which he established in 1978. Hood Companies Inc. consists of four separate corporations with 60 manufacturing and distribution sites throughout the United States, Canada, and Mexico. Hood Companies, Inc.'s products are currently marketed in North America, the Caribbean, and Western Europe. Mr. Hood previously served on the Board of the Company's subsidiary, Mississippi Power Company (Mississippi Power), where he was also a member of the Compensation Committee.
Mr. Hood has long been recognized for his leadership role in the State of Mississippi. He serves or has served on numerous corporate, community, and philanthropic boards, including Boy Scouts of America Pine Burr Area Council, Governor Phil Bryant's Mississippi Works Committee, and The Governor's Commission on Rebuilding, Recovery and Renewal, which was formed following Hurricane Katrina in 2005. He serves on the Board of BancorpSouth, Inc., where he is a member of the Audit Committee.

Mr. Hood's business operations, risk management, and financial experience and civic involvement are valuable to the Board.

Linda P. Hudson

Age: 64

Director since: 2014

Board committees: Governance, Nuclear/Operations, Business Security Subcommittee

Principal Occupation: Founder, Chairman, and Chief Executive Officer, The Cardea Group, business management consulting firm

Other public company directorships: BAE Systems, Inc., Bank of America Corporation

Director biography: Ms. Hudson is the Founder, Chairman, and Chief Executive Officer of The Cardea Group, a business management consulting firm she founded in 2014. From October 2009 through February 2014, Ms. Hudson served as the President and Chief Executive Officer of BAE Systems, Inc. (BAE Systems), a U.S.-based global defense, aerospace, and security company. BAE Systems is a wholly-owned subsidiary of London-based BAE Systems plc. Previously, Ms. Hudson served as President of BAE Systems' Land & Armaments operating group, the world's largest military vehicle and equipment business. Before joining BAE Systems in 2006, she served as Vice President of the General Dynamics Corporation and President of General Dynamics Armament and Technical Products. She currently serves as an adviser and outside Director for BAE Systems. She is also a member of Bank of America Corporation's Board of Directors, where she serves on the Compensation and Benefits Committee and the Credit Committee. She is also a Director of the University of Florida Foundation and a Director of the Center for a New American Security.

Ms. Hudson's experience leading a large, highly-regulated, complex business and expertise in engineering, technology, operations, and risk management are valuable to the Board.

Donald M. James

Age: 66

Director since: 1999

Board committees: Governance (Chair), Finance

Other public company directorships: Vulcan Materials Company, Wells Fargo & Company (formerly a Director of Protective Life Corporation)

Director biography: Mr. James retired from his position as Chief Executive Officer of Vulcan Materials Company in July 2014 and Executive Chairman in January 2015. He continues to serve as Chairman of the Board of Directors of Vulcan Materials Company. Mr. James joined Vulcan Materials Company in 1992 as Senior Vice President and General Counsel and then became President of the Southern Division and then Senior Vice President of the Construction Materials Group and President and Chief Executive Officer. Prior to joining Vulcan Materials Company, Mr. James was a partner at the law firm of Bradley, Arant, Rose & White for 10 years. Mr. James is also a Trustee of the UAB Health System and Children's of Alabama, where he serves on the Executive Committee. In addition, he serves on the Finance and the Human Resources Committees of Wells Fargo & Company's Board of Directors.

Mr. James' leadership of a large public company, his legal expertise, and his civic involvement are valuable assets to the Board.

John D. Johns

Age: 63

Director since: 2015

Board committees: Audit

Principal occupation: Chairman, President, and Chief Executive Officer of Protective Life Corporation (Protective Life)

Other public company directorships: Regions Financial Corporation, Genuine Parts Company (formerly a Director of Alabama Power Company)

Director biography: Mr. Johns has served as Chairman, President, and Chief Executive Officer of Protective Life since 2002. He joined Protective Life in 1993 as Executive Vice President and Chief Financial Officer. Before his tenure at Protective Life, Mr. Johns served as general counsel of Sonat, Inc., a diversified energy company. Prior to joining Sonat, Inc., Mr. Johns was a founding partner of the law firm Maynard Cooper & Gale. He previously served on the Board of Directors of Alabama Power Company (Alabama Power) from 2004 to 2015. During his tenure on the Alabama Power Board, he was a member of the Nominating Committee and Executive Committee. Mr. Johns has served on the Executive Committee of the Financial Services Roundtable in Washington, D.C., and is the immediate past chairman of the American Council of Life Insurers. He is a member of the Board of Directors of Regions Financial Corporation, where he serves on the Nominating and Governance and Risk Committees, and Genuine Parts Company, where he serves on the Compensation, Nominating and Governance Committee. Mr. Johns has served as the Chairman of the Business Council of Alabama, the Birmingham Business Alliance, the Greater Alabama Council, Boy Scouts of America, and Innovation Depot, Alabama's leading business and technology incubator.

Mr. Johns' management and leadership experience, his significant familiarity with Alabama Power, and his civic involvement are valuable to the Board.

Dale E. Klein

Age: 67

Director since: 2010

Board committees: Governance, Nuclear/Operations, Business Security Subcommittee (Chair)

Principal occupation: Associate Vice Chancellor of Research of the University of Texas System since 2011 and Associate Director of the Energy Institute at The University of Texas at Austin since 2010

Other public company directorships: Pinnacle West Capital Corporation, Arizona Public Service Company

Director biography: Dr. Klein was Commissioner from 2009 to 2010 and Chairman from 2006 through 2009 of the U.S. Nuclear Regulatory Commission. Dr. Klein also served as Assistant to the Secretary of Defense for Nuclear, Chemical, and Biological Defense Programs from 2001 through 2006. Dr. Klein has more than 35 years of experience in the nuclear energy industry. Dr. Klein began his career at the University of Texas in 1977 as a professor of mechanical engineering which included a focus on the university's nuclear program. He spent nearly 25 years in various teaching and leadership positions including Director of the nuclear engineering teaching laboratory, associate dean for research and administration in the College of Engineering, and vice-chancellor for special engineering programs. He serves on the Audit and Nuclear and Operating Committees of Pinnacle West Capital Corporation, an Arizona energy company, and is a member of the Board of Pinnacle West Capital Corporation's principal subsidiary, Arizona Public Service Company.

Dr. Klein's expertise in nuclear energy regulation and operations, technology, and safety is valuable to the Board.

William G. Smith, Jr.

Age: 61

Director since: 2006

Board committees: Finance (Chair), Compensation and Management Succession

Principal occupation: Chairman of the Board, President, and Chief Executive Officer of Capital City Bank Group, Inc., banking

Other public company directorships: Capital City Bank Group, Inc.

Director biography: Mr. Smith began his career at Capital City Bank in 1978, where he worked in a number of positions of increasing responsibility before being elected President and Chief Executive Officer of Capital City Bank Group, Inc. in January 1989. He was elected Chairman of the Board of the Capital City Bank Group, Inc. in 2003. He is also the Chairman and Chief Executive Officer of Capital City Bank. He previously served on the Board of Directors of the Federal Reserve Bank of Atlanta. He is the former Federal Advisory Council Representative for the Sixth District of the Federal Reserve System and past Chair of both Tallahassee Memorial HealthCare and the Tallahassee Area Chamber of Commerce.

Mr. Smith's experience in finance, business operations, and risk management is valuable to the Board.

Steven R. Specker

Age: 69

Director since: 2010

Board committees: Nuclear/Operations (Chair), Compensation and Management Succession

Other public company directorships: Trilliant Incorporated

Director biography: Dr. Specker served as President and Chief Executive Officer of the Electric Power Research Institute (EPRI) from 2004 until his retirement in 2010. Prior to joining EPRI, Dr. Specker founded Specker Consulting, LLC, a private consulting firm, which provided operational and strategic planning services to technology companies serving the global electric power industry. Dr. Specker also served in a number of leadership positions during his 30-year career at General Electric Company (GE), including serving as President of GE's nuclear energy business, President of GE digital energy, and Vice President of global marketing. Dr. Specker is also a member of the Board of Trilliant Incorporated, a leading provider of Smart Grid communication solutions.

Dr. Specker brings to the Board a keen understanding of the electric industry and valuable insight in innovation and technology development.

Larry D. Thompson

Age: 69

Director since: 2014 (previously served from 2010 to 2012)

Board committee: Audit

Other public company directorships: Franklin, Templeton Series Mutual Funds, Graham Holdings Company (formerly a Director of Cbeyond, Inc.)

Director biography: From 2012 until his retirement in 2014, Mr. Thompson served as Executive Vice President, Government Affairs, General Counsel, and Corporate Secretary for PepsiCo Inc., one of the world's largest packaged food and beverage companies. Prior to that, Mr. Thompson served from 2004 to 2011 as Senior Vice President of Government Affairs, General Counsel, and Corporate Secretary of PepsiCo Inc. In his role at PepsiCo Inc., Mr. Thompson was responsible for PepsiCo Inc.'s worldwide legal function, as well as its government affairs organization, and the company's charitable foundation. His government career includes serving as Deputy Attorney General in the United States Department of Justice and leading the National Security Coordination Council. In 2002, President George W. Bush named Mr. Thompson to head the Department of Justice's Corporate Fraud Task Force. Mr. Thompson is an Independent Trustee of various investment companies in the Franklin Templeton group of mutual funds and a Director and a member of the Compensation Committee of Graham Holdings Company (formerly The Washington Post Company). He also serves as a Director of the PepsiCo Foundation. Mr. Thompson served as a Director of Southern Company from 2010 to 2012 and was a member of the Audit Committee.

Mr. Thompson's government experience and corporate governance and legal expertise are valuable to the Board.

E. Jenner Wood III

Age: 63

Director since: 2012

Board committees: Governance, Nuclear/Operations

Principal occupation: Chairman and Chief Executive Officer of the Atlanta Division of SunTrust Bank and Corporate Executive Vice President of SunTrust Banks, Inc., banking

Other public company directorships: Genuine Parts Company, Oxford Industries, Inc. (formerly a Director of Crawford & Company and Georgia Power)

Director biography: Mr. Wood is currently the Chairman, President, and Chief Executive Officer of the Atlanta Division of SunTrust Bank, a position he has held since April 2014, where he is responsible for managing retail, commercial, and private wealth banking in the Greater Atlanta area. He also has served as an Executive Vice President of SunTrust Banks, Inc. since July 2005. From April 2010 through January 2013, he was Chairman of the Board, President, and Chief Executive Officer of the Atlanta/Georgia Division of SunTrust Bank and from January 2013 through March 2014 he was Chairman of the Board, President, and Chief Executive Officer of the Georgia/North Florida Division of SunTrust Bank. From 2002 through 2010, he served as Chairman, President, and Chief Executive Officer of SunTrust Bank Central Group with responsibility over Georgia and Tennessee. He served as a member of the Board of Georgia Power from 2002 until May 2012. During his tenure on the Georgia Power Board, he served as a member of the Compensation, Executive, and Finance Committees. Mr. Wood is a Director of Oxford Industries, Inc., where he serves as Presiding Director and as a member of the Executive Committee, and a Director of Genuine Parts Company, where he serves on the Audit Committee. He is active in numerous civic and community organizations, serving as a Trustee of the Robert W. Woodruff Foundation, The Sartain Lanier Family Foundation, Camp-Younts Foundation, the Jesse Parker Williams Foundation, and the William I. H. and Lula E. Pitts Foundation.

Mr. Wood's leadership experience and extensive background in finance as well as his involvement in the community are beneficial to the Board.

Each nominee has served in his or her present position for at least the past five years, unless otherwise noted.

The affirmative vote of a majority of the votes cast is required for the election of Directors at any meeting for the election of Directors at which a quorum is present. A majority of the votes cast means that the number of shares voted "FOR" the election of a Director must exceed the number of votes cast "AGAINST" the election of that Director.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" THE NOMINEES LISTED IN ITEM NO. 1.

ITEM NO. 2 — APPROVAL OF THE COMPANY'S OUTSIDE DIRECTORS STOCK PLAN

The Board of Directors has adopted effective June 1, 2015, subject to stockholder approval, the Outside Directors Stock Plan for Directors of The Southern Company and its Subsidiaries (Plan). The purpose of the Plan is to provide a mechanism for non-employee Directors to automatically increase their ownership of Common Stock and thereby further align their interests with those of the Company's stockholders.

The Plan will be administered by the Company's Governance Committee.

The Plan provides for the payment to non-employee Directors of a portion of their annual retainer fee in unrestricted shares of Common Stock. For the subsidiary company participants, the equity-based annual retainer fee that will be payable under the Plan in Common Stock ranges from $19,500 to $30,000 per year. See "Director Compensation" in this Proxy Statement for a description of the equity-based annual retainer fee paid to the Company's Directors. Additionally, the Plan permits participants to elect to receive a greater portion — up to all — of their Director compensation in Common Stock. For the Company's Directors, the receipt of Common Stock under the Plan is deferred until departure from the Board of Directors. Other subsidiary company participants may elect to defer receipt of all or a portion of Common Stock paid under the Plan until departure from their respective Board of Directors. The Company expects that there will be approximately 55 Company and subsidiary company Directors initially participating in the Plan.

The maximum amount of Common Stock that may be granted under the Plan is 1,000,000 shares.

The Board of Directors of the Company may amend or terminate the Plan at any time, subject to any required stockholder approval. The maximum amount of Common Stock that may be granted under the Plan may not be increased without stockholder approval.

The estimated amount to be paid to the Company's non-executive Directors as a group under the Plan in 2015 is $3.5 million. The actual number of shares of Common Stock to be received will be dependent upon the market price of the Common Stock on the date of grant. No amounts will be paid to executive officers or other employees under the Plan.

The text of the Plan is included as Appendix A to this Proxy Statement.

The affirmative vote of a majority of the votes cast is required for approval of the Plan.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 2.

ITEM NO. 3 — AMENDMENT TO THE COMPANY'S BY-LAWS RELATED TO THE ABILITY OF STOCKHOLDERS TO ACT BY WRITTEN CONSENT TO AMEND THE BY-LAWS

The Board of Directors has determined that it is in the best interests of the Company and its stockholders to amend the provision contained in Section 46 of the Company's By-Laws (By-Laws) relating to the ability of stockholders to act by written consent to amend the By-Laws. The proposed amendment would amend the By-Laws to permit stockholders to take action to amend the By-Laws without a meeting by the written consent of holders of not less than the minimum number of the issued and outstanding shares that would be necessary to take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Background of This Item

The Board of Directors is committed to implementing and maintaining effective corporate governance policies and practices which seek to ensure that the Company is governed with high standards of ethics, integrity, and accountability and in the best interest of the Company's stockholders. A written consent right generally affords stockholders a means of acting between annual meetings other than by calling a special meeting. Under Section 228(a) of the Delaware General Corporation Law (DGCL), any action that may be taken at a meeting of stockholders may be taken without a meeting "by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted," unless otherwise provided in the certificate of incorporation. The Company's Certificate of Incorporation permits the Company's stockholders to act by written consent because it does not restrict that right. The only provision in the By-Laws that concerns stockholders' ability to act by written consent is contained in Section 46, which provides that stockholders may amend the By-Laws without a meeting but only by unanimous written consent. The Board of Directors has determined that revising this provision in the By-Laws to make it consistent with Section 228(a) of the DGCL and the Company's Certificate of Incorporation is in the best interests of the Company and its stockholders.

As a result, the Board of Directors voted to approve, and to recommend to the Company's stockholders that they approve, a proposal to amend Section 46 of the By-Laws to permit stockholders to take action to amend the By-Laws without a meeting by the written consent of holders of not less than the minimum number of the issued and outstanding shares of capital stock of the Company having voting powers that would be necessary to take such action at a meeting at which all shares entitled to vote thereon were present and voted. Under the By-Laws, the proposed amendment to Section 46 of the By-Laws requires stockholder approval in order to become effective.

Amendment

The proposed amendment to Section 46 of the By-Laws would revise the provision that relates to the ability of stockholders to act by written consent to amend the By-Laws. If approved, this proposed amendment would conform Section 46 of the By-Laws to Section 228 of the DGCL and the Company's Certificate of Incorporation to make clear that the standard set forth in Section 228(a) of the DGCL governs the ability of the Company's stockholders to act by written consent.

The text of the proposed amendment, marked to show changes to the current Section 46 of the By-Laws, is included as Appendix B to this Proxy Statement.

The affirmative vote of a majority of the shares represented in person or by proxy and entitled to vote at the annual meeting is required for approval of the proposed amendment to Section 46 of the By-Laws as presented in this Item No. 3.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 3.

Company Organization

Southern Company is a holding company managed by a core group of officers and governed by a Board of Directors that is currently comprised of 15 members.

At the 2015 Annual Meeting, stockholders will elect 15 Directors. The nominees for election as Directors consist of 14 non-employees and one executive officer of the Company.

The Board of Directors has adopted and operates under a set of Corporate Governance Guidelines which are available on the Company's website at www.southerncompany.com under Information for Investors/Corporate Governance.

Corporate Governance Website

In addition to the Company's Corporate Governance Guidelines (which include Board independence criteria), other information relating to corporate governance of the Company is available on the Company's Corporate Governance webpage at www.southerncompany.com under Information for Investors/Corporate Governance.

- Code of Ethics
- By-Laws
- Executive Stock Ownership Requirements
- Board Committee Charters
- Board of Directors — Background and Experience
- Management Council — Background and Experience
- Composition of Board Committees
- SEC filings
- Link for on-line communication with Board of Directors
- Political Spending and Lobbying-Related Activities
- Anti-Hedging Provision

The Corporate Governance documents also may be obtained by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Director Independence

No Director will be deemed to be independent unless the Board of Directors affirmatively determines that the Director has no material relationship with the Company directly or as an officer, stockholder, or partner of an organization that has a relationship with the Company. The Board of Directors has adopted categorical guidelines which provide that a Director will not be deemed to be independent if within the preceding three years:

- The Director was employed by the Company or the Director's immediate family member was an executive officer of the Company.
- The Director has received, or the Director's immediate family member has received, during any 12-month period, direct compensation from the Company of more than $120,000, other than Director and committee fees. (Compensation received by an immediate family member for service as a non-executive employee of the Company need not be considered.)
- The Director was affiliated with or employed by, or the Director's immediate family member was affiliated with or employed in a professional capacity by, a present or former external auditor of the Company and personally worked on the Company's audit.
- The Director was employed, or the Director's immediate family member was employed, as an executive officer of a company where any member of the Company's present executive officers at the same time served on that company's compensation committee.
- The Director is a current employee, or the Director's immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the Company for property or services in an amount which, in any year, exceeds the greater of $1,000,000 or two percent of that company's consolidated gross revenues.
- The Director or the Director's spouse serves as an executive officer of a charitable organization to which the Company made discretionary contributions which, in any year, exceeds the greater of $1,000,000 or two percent of the organization's consolidated gross revenues.

At least annually, the Board receives a report on all commercial, consulting, legal, accounting, charitable, or other business relationships that a Director or the Director's immediate family members have with the Company. This report specifically includes all ordinary course transactions with entities with which the Directors are associated. The Board determined that the Company and its subsidiaries followed the Company's procurement policies and procedures, that the amounts reported were well under the thresholds contained in the Director independence requirements, and that no Director had a direct or indirect material interest in the transactions. See Other Information — Certain Relationships and Related Transactions for a discussion of related party transactions identified by the Company.

The Board reviewed all contributions made by the Company and its subsidiaries to charitable organizations with which the Directors are associated. The Board determined that the contributions were consistent with other contributions by the Company and its subsidiaries to charitable organizations and none were approved outside the Company's normal procedures.

At least annually, the Board also reviews Director independence. The Board considers transactions, if any, identified in the review of the report discussed above that affect Director independence, including any transactions in which the amounts reported were above the threshold contained in the Director independence requirements and in which a Director had a direct or indirect material interest. No such transactions were identified and, as a result, no such transactions were considered by the Board. In determining independence, the Board also considered that, in the ordinary course of the Southern Company system's business, electricity is provided to some Directors and entities with which the Directors are associated on the same terms and conditions as provided to other customers of the Southern Company system.

As a result of its review of Director independence, the Board affirmatively determined that none of the following persons who are currently serving as Directors or who served during 2014 or who are nominees for election as Directors has a material relationship with the Company and, as a result, such persons are determined to be independent: Juanita Powell Baranco, Jon A. Boscia, Henry A. Clark III, David J. Grain, H. William Habermeyer, Jr., Veronica M. Hagen, Warren A. Hood, Jr., Linda P. Hudson, Donald M. James, John D. Johns, Dale E. Klein, William G. Smith, Jr., Steven R. Specker, Larry D. Thompson, and E. Jenner Wood III. Thomas A. Fanning, a current Director, is Chairman of the Board, President, and Chief Executive Officer of the Company and is not independent.

Communicating with the Board

Interested parties may communicate directly with the Company's Board or specified Directors, including the Lead Independent Director. Communications may be sent to the Company's Board or to specified Directors, including the Lead Independent Director, by regular mail or electronic mail. Regular mail should be sent to the attention of Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. The electronic mail address is CORPGOV@southerncompany.com. The electronic mail address also can be accessed from the Corporate Governance webpage located under Information for Investors/ Corporate Governance on the Company's website at www.southerncompany.com, under the link entitled Governance Inquiries. With the exception of commercial solicitations, all communications directed to the Board or to specified Directors will be relayed to them.

Stakeholder Engagement

The Company places great importance on consistent dialogue with its stakeholders, including customers, investors, and employees as well as with the financial community generally. The Company also regularly engages in discussions with, and provides comprehensive information for, its constituents interested in the Southern Company system's citizenship, stewardship, and environmental compliance. As part of these efforts, in 2014, the Company began a more systematic approach to investor outreach and involved members of its senior management and the Board of Directors. These efforts included a specific focus on the Company's corporate governance philosophy and practices and its desire to hear about the governance topics of specific interest to its stockholders. Moving forward, the Company will continue to take an active, inclusive, and flexible approach to stakeholder engagement.

Majority Voting for Directors

Since 2010, the Company has had a majority vote standard for Director elections, which requires that a nominee for Director in an uncontested election receive a majority of the votes cast at a stockholder meeting in order to be elected to the Board. The Board believes this standard for uncontested elections is a more equitable standard than a plurality vote standard. A plurality vote standard guarantees the election of a Director in an uncontested election; however, a majority vote standard means that nominees in uncontested elections are only elected if a majority of the votes cast are voted in their favor. The Board believes that the majority vote standard in uncontested Director elections strengthens the Director nomination process and enhances Director accountability.

The Company also has a resignation policy, which requires any nominee for election as a Director to submit an irrevocable letter of resignation as a condition to being named as such nominee, which would be tendered in the event that nominee fails to receive the affirmative vote of a majority of the votes cast in an uncontested election at a meeting of stockholders. Such resignation would be considered by the Board, and the Board would be required to either accept or reject such resignation within 90 days from the certification of the election results.

Political Contributions Policy

The Board reviews the Company's political contributions and its policies and procedures regarding political contributions. Any corporate political contributions or independent expenditures made by the Company and its subsidiaries in connection with elections for public office, as well as any payments made by the Company and its subsidiaries to other organizations that are designated for their use in making political contributions or independent expenditures, are reviewed at least annually with the Board. Any corporate contributions to ballot initiative campaign committees also are reviewed annually with the Board.

Director Compensation

Only non-employee Directors of the Company are compensated for service on the Board of Directors. During 2014, the pay components for non-employee Directors were:

Annual retainers:

- $100,000 cash retainer
- Additional $20,000 cash retainer if serving as a chair of a committee of the Board
- Additional $20,000 cash retainer if serving as the Lead Independent Director of the Board

Annual equity grant:

- $120,000 in deferred Common Stock units until Board membership ends

Meeting fees:

- Meeting fees are not paid for participation in the initial eight meetings of the Board in a calendar year. If more than eight meetings of the Board are held in a calendar year, $2,500 will be paid for participation in each meeting of the Board beginning with the ninth meeting.
- Meeting fees are not paid for participation in a meeting of a committee of the Board.

On December 8, 2014, the Board of Directors created a Business Security Subcommittee of the Nuclear/Operations Committee and approved an additional $12,500 annual cash retainer for serving on such subcommittee.

Director Deferred Compensation Plan

The annual equity grant is required to be deferred in shares of Common Stock under the Deferred Compensation Plan for Outside Directors of The Southern Company, as amended and restated effective January 1, 2008 (Director Deferred Compensation Plan), and invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the Board, distributions are made in Common Stock or cash.

In addition, Directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the Board ends. Such deferred compensation may be invested as follows, at the Director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock or cash upon leaving the Board; or
- at the prime interest rate which is paid in cash upon leaving the Board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the Director, may be distributed in a lump-sum payment, or in up to 10 annual distributions after leaving the Board. The Company has established a grantor trust that primarily holds Common Stock that funds the Common Stock units that are distributed in shares of Common Stock. Directors have voting rights in the shares held in the trust attributable to these units.

Director Compensation Table

The following table reports all compensation to the Company's non-employee Directors during 2014, including amounts deferred in the Director Deferred Compensation Plan. Non-employee Directors do not receive Option Awards or Non-Equity Incentive Plan Compensation, and there is no pension plan for non-employee Directors. Mr. Johns, who was elected to the Board effective February 9, 2015, is not included in this table.

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Juanita Powell Baranco	116,667	120,000	—	—	—	1,502	238,169
Jon A. Boscia	120,000	120,000	—	—	—	1,499	241,499
Henry A. Clark III	111,667	120,000	—	—	—	1,723	233,390
David J. Grain	100,001	120,000	—	—	—	1,310	221,311
H. William Habermeyer, Jr. (4)	50,000	50,000	—	—	—	280	100,280
Veronica M. Hagen	120,000	120,000	—	—	—	1,453	241,453
Warren A. Hood, Jr.	100,001	120,000	—	—	—	1,443	221,444
Linda P. Hudson (5)	75,001	90,000	—	—	—	1,301	166,302
Donald M. James	111,667	120,000	—	—	—	1,647	233,314
Dale E. Klein	100,001	120,000	—	—	—	1,175	221,176
William G. Smith, Jr.	120,000	120,000	—	—	—	1,175	241,175
Steven R. Specker	111,667	120,000	—	—	—	1,559	233,226
Larry D. Thompson (6)	8,333	10,000	—	—	—	1,077	19,410
E. Jenner Wood III	100,001	120,000	—	—	—	1,675	221,676

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.
(2) Represents the grant date fair market value of deferred Common Stock units.
(3) Consists of tax reimbursements for taxes on imputed income associated with gifts and activities provided to attendees at Company-sponsored events.
(4) Mr. Habermeyer retired from the Board effective May 28, 2014.
(5) Ms. Hudson was elected to the Board effective March 1, 2014.
(6) Mr. Thompson was elected to the Board effective December 1, 2014.

Director Stock Ownership Guidelines

Under the Company's Corporate Governance Guidelines, non-employee Directors are required to beneficially own, within five years of their initial election to the Board, Common Stock equal to at least five times the annual Director cash retainer fee. Also, as described in the Director Compensation section above, the annual equity grant received as a part of the annual compensation for non-employee Directors is required to be deferred until Board membership ends. All non-employee Directors either meet the stock ownership guideline or are expected to meet the guideline within the allowed timeframe.

Board Leadership Structure

The Board believes that its current leadership structure, which has a combined role of Chief Executive Officer and Chairman counterbalanced by a strong independent Board led by a Lead Independent Director, is most suitable for the Company at this time. The combined role of Chief Executive Officer and Chairman is held by Mr. Fanning who is the Director most familiar with the Company's business and industry, including the regulatory structure and other industry-specific matters, as well as being most capable of effectively identifying strategic priorities and leading discussion and execution of strategy. Independent Directors and management have different perspectives and roles in strategy development. The Chief Executive Officer brings Company-specific experience and expertise, while the Company's independent Directors bring experience, oversight, and expertise from outside the Company and its industry. The Board believes that the combined role of Chief Executive Officer and Chairman promotes the development and execution of the Company's strategy and facilitates the flow of information between management and the Board, which is essential to effective corporate governance.

The Board believes the combined role of Chief Executive Officer and Chairman, together with a strong Lead Independent Director having the duties described below, is in the best interest of stockholders because it provides the optimal balance between independent oversight of management and unified leadership.

Lead Independent Director

The Lead Independent Director is elected every two years by the independent Directors. Non-management Directors meet, without management, on each regularly-scheduled Board meeting date, and at other times as deemed appropriate by the Lead Independent Director or two or more other independent Directors.

The Lead Independent Director has the following powers and responsibilities:

- approving the agenda and schedule for Board meetings and information sent to the Board;
- calling and chairing executive sessions of the non-management Directors;
- chairing Board meetings in the absence of the Chairman;
- meeting regularly with the Chairman;
- acting as the principal liaison between the Chairman and the non-management Directors (however, each Director has direct and complete access to the Chairman at any time);
- serving as the primary contact Director for stockholders and other interested parties; and
- communicating any sensitive issues to the Directors.

Ms. Veronica M. Hagen currently serves as the Company's Lead Independent Director. Mr. William G. Smith, Jr. served as the Company's Presiding Director effective May 23, 2012 until May 28, 2014. In February 2014, Ms. Hagen was appointed to serve as the Presiding Director effective May 28, 2014 until the Company's 2016 Annual Meeting of Stockholders. On July 21, 2014, the Board of Directors approved an amendment to the Company's Corporate Governance Guidelines changing the Presiding Director's title to "Lead Independent Director" and enhancing the Lead Independent Director's responsibilities, including noting that the Lead Independent Director approves the agenda and schedule for Board meetings and information sent to the Board.

Meetings of Non-Management Directors

Non-management Directors meet in executive session without any members of the Company's management present on each regularly-scheduled Board meeting date. These executive sessions promote an open discussion of matters in a manner that is independent of the Chairman and Chief Executive Officer. The Lead Independent Director chairs each of these executive sessions.

Committees of the Board

Charters for each of the five standing committees can be found at the Company's website — www.southerncompany.com under Information for Investors/Corporate Governance.

Audit Committee

Jon A. Boscia
Chair

- Current members are Mr. Boscia *(Chair)*, Ms. Baranco,[(1)] Mr. Hood, Mr. Johns,[(2)] and Mr. Thompson.[(1)]
- Met ten times in 2014
- The Audit Committee's duties and responsibilities, which are described in its charter, include the following:
  - Oversee the Company's financial reporting, audit processes, internal controls, and legal, regulatory, and ethical compliance.
  - Appoint the Company's independent registered public accounting firm, approve its services and fees, and establish and review the scope and timing of its audits.
  - Review and discuss the Company's financial statements with management, the internal auditors, and the independent registered public accounting firm, including critical accounting policies and practices, material alternative financial treatments within generally accepted accounting principles, proposed adjustments, control recommendations, significant management judgments and accounting estimates, new accounting policies, changes in accounting principles, any disagreements with management, and other material written communications between the internal auditors and/or the independent registered public accounting firm and management.
  - Recommend the filing of the Company's and its registrant subsidiaries' annual financial statements with the SEC.

The Board has determined that the members of the Audit Committee are independent as defined by the New York Stock Exchange (NYSE) corporate governance rules within its listing standards and rules of the SEC promulgated pursuant to the Sarbanes-Oxley Act of 2002. The Board has determined that Mr. Boscia qualifies as an "audit committee financial expert" as defined by the SEC.

(1) Ms. Baranco and Mr. Thompson were appointed as members of the Audit Committee effective December 1, 2014.
(2) Mr. Johns was appointed a member of the Audit Committee effective March 1, 2015.

Compensation and Management Succession Committee (Compensation Committee)

Henry A. "Hal" Clark III
Chair

- Current members are Mr. Clark *(Chair)*, Mr. Grain,[(1)] Ms. Hagen, Mr. Smith, and Dr. Specker.[(2)]
- Met seven times in 2014
- The Compensation Committee's duties and responsibilities, which are described in its charter, include the following:
  - Evaluate performance of executive officers and establish their compensation, administer executive compensation plans, and review management succession plans.
  - Annually review a tally sheet of all components of the executive officers' compensation and take actions required of it under the Pension Plan for employees of the Company's subsidiaries.

The Board has determined that each member of the Compensation Committee is independent.

(1) Mr. Grain was appointed as a member of the Compensation Committee effective December 1, 2014.
(2) Dr. Specker was appointed a member of the Compensation Committee effective May 28, 2014.

Committee Governance

During 2014, the Compensation Committee's governance practices included:

- Considering compensation for the named executive officers in the context of all of the components of total compensation;
- Considering annual adjustments to pay over the course of two meetings and requiring more than one meeting to make other important decisions;
- Receiving meeting materials several days in advance of meetings;
- Having regular executive sessions of Compensation Committee members only;
- Having direct access to independent compensation consultants;
- Conducting a performance/payout analysis versus peer companies for the performance-based compensation program to provide a check on the Company's goal-setting process; and
- Reviewing a compensation risk assessment through a process developed by its independent compensation consultant.

Role of Executive Officers

The Chief Executive Officer, with input from the Company's Human Resources staff, recommends to the Compensation Committee: base salary, target performance-based compensation levels, actual performance-based compensation payouts, and long-term performance-based grants for the Company's executive officers (other than the Chief Executive Officer). The Compensation Committee considers, discusses, modifies as appropriate, and takes action on such recommendations.

Role of Compensation Consultant

The Compensation Committee, which has authority to retain independent advisors, including compensation consultants, at the Company's expense, engaged Pay Governance LLC (Pay Governance) to provide an independent assessment of the current executive compensation program and any management-recommended changes to that program and to work with Company management to ensure that the executive compensation program is designed and administered consistent with the Compensation Committee's requirements. The Compensation Committee also expected Pay Governance to advise on executive compensation and related corporate governance trends.

Pay Governance is engaged solely by the Compensation Committee and does not provide any services directly to management unless authorized to do so by the Compensation Committee. In connection with its engagement of Pay Governance, the Compensation Committee reviewed Pay Governance's independence including (1) the amount of fees received by Pay Governance from the Company as a percentage of Pay Governance's total revenue; (2) its policies and procedures designed to prevent conflicts of interest; and (3) the existence of any business or personal relationships, including Common Stock ownership, that could impact independence. After reviewing these and other factors, the Compensation Committee determined that Pay Governance is independent and the engagement did not present any conflicts of interest. Pay Governance also determined that it was independent from management, which was confirmed in a written statement delivered to the Compensation Committee.

During 2014, Pay Governance assisted the Compensation Committee with analyzing comprehensive market data and its implications for pay at the Company and its affiliates and various other governance, design, and compliance matters.

Finance Committee

William G. Smith, Jr.
Chair

- Current members are Mr. Smith (*Chair*), Mr. Clark, Mr. Grain,(1) and Mr. James
- Met seven times in 2014
- The Finance Committee's duties and responsibilities, which are described in its charter, include the following:
  - Review the Company's financial matters and recommend actions such as dividend philosophy and financial plan approval to the Board.
  - Provide input to the Compensation Committee regarding the Company's financial plan and associated financial goals.

The Board has determined that each member of the Finance Committee is independent.

(1) Mr. Grain was appointed a member of the Finance Committee effective December 1, 2014.

Governance Committee

Donald M. James
Chair

- Current members are Mr. James (*Chair*), Ms. Hudson,(1) Dr. Klein, and Mr. Wood
- Met six times in 2014
- The Governance Committee's duties and responsibilities, which are described in its charter, include the following:
  - Recommend Board size and membership criteria and identify, evaluate, and recommend Director candidates.
  - Oversee and make recommendations regarding the composition of the Board and its committees.
  - Review and make recommendations regarding total compensation for non-employee Directors.
  - Periodically review and recommend updates to the Corporate Governance Guidelines and Board committee charters.
  - Coordinate the performance evaluations of the Board and its committees.
  - Review stock ownership of non-employee Directors annually to ensure compliance with the Company's Director stock ownership guidelines.

The Board has determined that each member of the Governance Committee is independent.

(1) Ms. Hudson was appointed as a member of the Governance Committee effective December 1, 2014.

Nominees for Election to the Board

The Governance Committee, comprised entirely of independent Directors, is responsible for identifying, evaluating, and recommending nominees for election to the Board. The Governance Committee solicits recommendations for candidates for consideration from its current Directors and is authorized to engage third-party advisers to assist in the identification and evaluation of candidates for consideration. Any stockholder may make recommendations to the Governance Committee by sending a written statement describing the candidate's qualifications, relevant biographical information, and signed consent to serve. These materials should be submitted in writing to the Company's Corporate Secretary and received by that office by December 12, 2015 for consideration by the Governance Committee as a nominee for election at the Annual Meeting of Stockholders to be held in 2016. Any stockholder recommendation is reviewed in the same manner as candidates identified by the Governance Committee or recommended to the Governance Committee.

While the Company's Corporate Governance Guidelines do not prescribe diversity standards, such Guidelines mandate that the Board as a whole should be diverse. At least annually, the Governance Committee evaluates the expertise and needs of the Board to determine the proper membership and size. As part of this evaluation, the Governance Committee considers aspects of diversity, such as diversity of age, race, gender, education, industry, business background, and civic service, in the selection of candidates to serve on the Board. In addition, the Governance Committee also seeks to identify candidates with the capacity to bring relevant experience, relationships, and perspectives regarding the service territories of the Company's traditional operating subsidiaries, which are primarily in the

Southeastern United States. Accordingly, the Company uniquely benefits from the experience of Directors who have previously served on the boards of the Company's subsidiary companies. These operating company boards provide an opportunity for Director candidates to cultivate significant relevant experience with the Company's business.

The Governance Committee only considers candidates with the highest degree of integrity and ethical standards. The Governance Committee evaluates a candidate's independence from management, ability to provide sound and informed judgment, history of achievement reflecting superior standards, willingness to commit sufficient time, financial literacy, number of other board memberships, genuine interest in the Company and a recognition that, as a member of the Board, one is accountable to the stockholders of the Company, not to any particular interest group. The Board as a whole should also have collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and the Company's industry and service territories.

The Governance Committee recommends candidates to the Board for consideration as nominees. Final selection of the nominees is within the sole discretion of the Board.

Messrs. Larry D. Thompson and John D. Johns were recommended by the Governance Committee for election to the Board and were elected as a Director effective December 1, 2014 and February 9, 2015, respectively. Messrs. Thompson and Johns were identified jointly by members of the Board and management.

Nuclear/Operations Committee

Steven R. Specker
Chair

- Current members are Dr. Specker (Chair), Ms. Hagen, Ms. Hudson,(1) Dr. Klein, and Mr. Wood
- Met five times in 2014
- The Nuclear/Operations Committee's duties and responsibilities, which are described in its charter, include the following:
  - Oversee information, activities, and events relative to significant operations of the Southern Company system including nuclear and other power generation facilities, transmission and distribution, fuel, and information technology initiatives.
  - Oversee the Southern Company system's management of significant construction projects.
  - Provide input to the Compensation Committee on the Southern Company system's key operational goals and metrics.

The Board has determined that each member of the Nuclear/Operations Committee is independent.

(1) Ms. Hudson was appointed a member of the Nuclear/Operations Committee effective December 1, 2014.

Business Security Subcommittee

In 2014, the Board established a Business Security Subcommittee of the Nuclear/Operations Committee, comprised of Dr. Klein (Chair) and Ms. Hudson. The Business Security Subcommittee's responsibilities include oversight of management's efforts to establish and continuously improve enterprise-wide security policies, programs, standards, and controls and oversight of management's efforts to monitor significant security events and operational and compliance activities.

Board Risk Oversight

The Board and its committees have both general and specific risk oversight responsibilities. The Board has broad responsibility to provide oversight of significant risks to the Company primarily through direct engagement with Company management and through delegation of ongoing risk oversight responsibilities to the committees. The charters of the committees as approved by the Board and the committees' checklists of agenda items define the areas of risk for which each committee is responsible for providing ongoing oversight.

Each committee annually provides ongoing oversight for each of the Company's most significant risks designated to it as described in its charter or otherwise assigned by the Board, reports to the Board on their oversight activities, and elevates review of risk issues to the Board as appropriate.

For each committee, the Chief Executive Officer of the Company has designated a member of executive management as the primary responsible officer for providing information and updates related to the significant risks. These officers ensure that all significant risks identified on the Company's risk profile are reviewed with the Board and/or the appropriate committee(s) at least annually.

In addition to oversight of its designated risks, the Audit Committee is also responsible for reviewing the adequacy of the risk oversight process and for reviewing documentation that appropriate risk management and oversight are occurring. In order to fulfill this duty, a report is made to the Audit Committee at least annually. This report documents which significant risk reviews have occurred and the committee(s) reviewing such risks. In addition, an overview is provided at least annually of the risk assessment and profile process conducted by Company management. At least annually, the Board and the Audit Committee review the Company's risk profile to ensure that oversight of each risk is properly designated to an appropriate committee or the full Board. Additionally, the Audit Committee receives regular updates from Internal Auditing, as needed, and quarterly updates as part of the disclosure controls process.

The Company believes that its leadership structure supports the risk oversight function of the Board. While the Company has a combined role of Chairman and Chief Executive Officer, an independent Director chairs each committee responsible for providing ongoing oversight of certain areas of risk. Also, there is open communication between the Company's management and the Directors and all Directors are actively involved in the risk oversight function.

Director Attendance

The Board of Directors met seven times in 2014. Average Director attendance at all applicable Board and committee meetings was 98%. No nominee attended less than 75% of applicable meetings.

All Director nominees are expected to attend the Annual Meeting of Stockholders. All the members of the Board of Directors serving on May 28, 2014, the date of the 2014 Annual Meeting of Stockholders, attended the meeting.

Stock Ownership of Directors, Nominees, and Executive Officers

The following table shows the number of shares of Common Stock beneficially owned by Directors, nominees, and executive officers as of February 28, 2015. The shares owned by all Directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares of Common Stock outstanding.

		Shares Beneficially Owned Include:		
Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Deferred Common Stock Units (2)	Shares Individuals Have Rights to Acquire within 60 Days (3)	Shares Held by Family Member (4)
Juanita Powell Baranco	70,407	69,748	—	—
Art P. Beattie	523,200	—	507,587	51
Jon A. Boscia	80,918	21,918	—	—
W. Paul Bowers	1,169,695	—	1,108,858	—
Henry A. Clark III	15,587	15,587	—	—
Thomas A. Fanning	1,461,568	—	1,415,361	—
David J. Grain	20,793	10,002	—	—
Kimberly S. Greene	299,603	—	299,603	—
Veronica M. Hagen	37,138	37,138	—	—
Warren A. Hood, Jr.	47,524	46,863	—	—
Linda P. Hudson	2,696	2,696	—	—
Donald M. James	98,581	98,581	—	—
John D. Johns (5)	22,365	21,915	—	450
Dale E. Klein	12,690	12,690	—	—
Stephen E. Kuczynski	629,919	—	619,320	—
William G. Smith, Jr.	64,331	57,535	—	862
Steven R. Specker	11,937	11,937	—	—
Larry D. Thompson (6)	13,347	1,120	—	—
E. Jenner Wood III	24,204	19,204	—	—
Directors, Nominees, and Executive Officers as a Group (25 people) (7)	6,513,643	426,935	5,774,784	1,363

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security, or investment power with respect to a security, or any combination thereof.

(2) Indicates the number of deferred Common Stock units held under the Director Deferred Compensation Plan that are payable in Common Stock or cash upon departure from the Board. Shares indicated are included in the Shares Beneficially Owned column.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

(4) Each Director disclaims any interest in shares held by family members. Shares indicated are included in the Shares Beneficially Owned column.

(5) Mr. Johns was elected to the Board effective February 9, 2015.

(6) Mr. Thompson was elected to the Board effective December 1, 2014.

(7) This item includes all executive officers serving as of February 28, 2015.

Stock Ownership of Certain Other Beneficial Owners

According to a Schedule 13G/A filed with the SEC on February 9, 2015 by Blackrock, Inc., a schedule 13G filed with the SEC on February 12, 2015 by State Street Corporation, and a Schedule 13G/A filed with the SEC on February 11, 2015 by The Vanguard Group (collectively, the Ownership Reports), the following reported beneficial ownership of more than 5% of the outstanding shares of Common Stock:

Title of Class	Name and Address	Shares Beneficially Owned (1)	Percentage of Class Owned (2)
Common Stock	Blackrock, Inc. 55 East 52nd Street New York, NY 10022	52,684,667	5.79
Common Stock	State Street Corporation One Lincoln Street Boston, MA 02111	46,254,789	5.08
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	51,373,414	5.65

(1) According to the Ownership Reports, Blackrock Inc. and State Street Corporation each held all of its shares as a parent holding company or control person in accordance with Rule 13(d)-1(b)(1)(ii)(G) and The Vanguard Group held all of its shares as an investment advisor in accordance with Rule 13(d)-1(b)(1)(ii)(E). According to the Ownership Reports, Blackrock Inc. has sole voting power with respect to 44,684,178 of its shares and sole dispositive power with respect to all 52,684,667 of its shares; State Street Corporation has shared voting and dispositive power with respect to all 46,254,789 of its shares; and The Vanguard Group has sole voting power with respect to 1,603,512 of its shares, sole dispositive power with respect to 49,912,177 of its shares, and shared dispositive power with respect to 1,461,237 of its shares.

(2) Calculated based on 909,877,898 shares outstanding as of January 31, 2015.

ITEM NO. 4 — ADVISORY VOTE ON NAMED EXECUTIVE OFFICERS' COMPENSATION

(the Say-on-Pay vote)

At the 2014 Annual Meeting of Stockholders, the Company provided stockholders with the opportunity to cast an advisory vote regarding the compensation of the named executive officers as disclosed in the 2014 Proxy Statement for the 2014 Annual Meeting of Stockholders. At the meeting, stockholders strongly approved the proposal, with more than 94% of the votes cast voting in favor of the proposal. At the 2011 Annual Meeting, stockholders were asked how frequently the Company should hold a say-on-pay vote — whether every one, two, or three years. Consistent with the recommendation of the Board of Directors, stockholders indicated their preference to hold a say-on-pay vote annually. In light of the Board of Directors' recommendation and the strong support of the Company's stockholders, the Board of Directors determined to hold a say-on-pay vote annually.

As described in the Compensation Discussion and Analysis (CD&A) in this Proxy Statement, the Compensation Committee has structured the Company's executive compensation program based on the belief that executive compensation should:

- Be competitive with the Company's industry peers;
- Motivate and reward achievement of the Company's goals;
- Be aligned with the interests of the Company's stockholders and its subsidiaries' customers; and
- Not encourage excessive risk-taking.

The Company believes these objectives are accomplished through a compensation program that provides the appropriate mix of fixed and short- and long-term performance-based compensation that rewards achievement of the Company's financial success, business unit financial and operational success, and total shareholder return. The Company's financial and operational achievement in 2014 resulted in performance-based awards that were aligned with performance.

All decisions concerning the compensation of the Company's named executive officers are made by the Compensation Committee, an independent Board committee, with the advice and counsel of an independent executive compensation consultant, Pay Governance.

The Company encourages stockholders to read the Executive Compensation section of this Proxy Statement which includes the CD&A, the Summary Compensation Table, and other related compensation tables, including the information accompanying these tables.

Although it is non-binding on the Board of Directors, the Compensation Committee will review and consider the vote results when making future decisions about the Company's executive compensation program.

The affirmative vote of a majority of the votes cast is required for approval of the following resolution:

"RESOLVED, that the Company's stockholders approve, on an advisory basis, the compensation of the Company's named executive officers, as disclosed in the Proxy Statement for the 2015 Annual Meeting of Stockholders pursuant to the compensation disclosure rules of the Securities and Exchange Commission, including the Compensation Discussion and Analysis, the 2014 Summary Compensation Table, and the other related tables and accompanying narrative set forth in the Proxy Statement."

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 4.

Index to Executive Compensation

This section describes the compensation program for the Company's Chief Executive Officer and Chief Financial Officer in 2014, as well as the compensation program for each of the Company's other three most highly compensated executive officers serving at the end of the year. Also described is the compensation of Alabama Power's former President and Chief Executive Officer, Charles D. McCrary, who retired effective May 1, 2014. Collectively, these officers are referred to as the named executive officers.

Thomas A. Fanning	Chairman of the Board, President, and Chief Executive Officer
Art P. Beattie	Executive Vice President and Chief Financial Officer
W. Paul Bowers	Executive Vice President of the Company and Chairman, President, and Chief Executive Officer of Georgia Power
Kimberly S. Greene (1)	Executive Vice President and Chief Operating Officer of the Company
Stephen E. Kuczynski	President and Chief Executive Officer of Southern Nuclear Operating Company (Southern Nuclear)
Charles D. McCrary	Former Executive Vice President of the Company and former Chairman, President, and Chief Executive Officer of Alabama Power

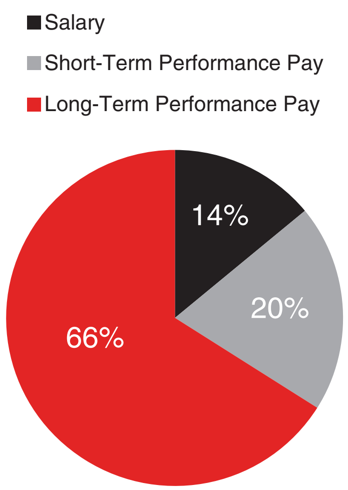
(1) Prior to becoming Executive Vice President and Chief Operating Officer of the Company in March 2014, Ms. Greene served as Executive Vice President of the Company and President and Chief Executive Officer of Southern Company Services, Inc. (SCS).

Executive Summary

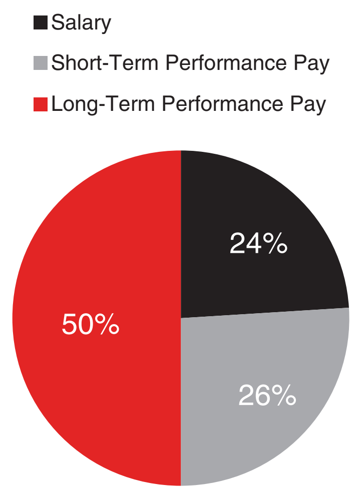
Performance and Pay

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2014. Performance-based pay includes both short-term compensation payable in cash on an annual basis (Performance Pay Program) and long-term, equity-based compensation (performance shares and stock options). Both short-term and long-term pay ultimately depend on the financial and operational performance of the Company and its business units.

Chief Executive Officer (1)



Other Named Executive Officers (1)



(1) Salary is the actual amount paid in 2014, Short-Term Performance Pay is the actual amount earned in 2014 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2014. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A. Information is provided for named executive officers serving at the end of 2014.

Short-term performance pay is based on achievement of financial and operational goals that include Company earnings per share (EPS) and business unit financial and operational goals. Company EPS and business unit financial and operational achievement results for 2014, as adjusted and further described in this CD&A, are shown below:

	EPS	Alabama Power Net Income	Georgia Power Net Income	Gulf Power Net Income	Mississippi Power Net Income	Southern Power Net Income	Equity-Weighted Average Net Income
Financial Achievement Results	176%	176%	167%	100%	124%	193%	163%

	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operations	Safety	Plant Vogtle Units 3 and 4 and Kemper IGCC	Culture	Aggregate Corporate Performance
Corporate Operational Achievement Results	200%	195%	190%	150%	167%	Plant Vogtle: 175% Kemper IGCC: 75%	150%	172%

These performance levels resulted in a composite corporate performance score of 170% of target under the short-term Performance Pay Program.

Long-term performance pay includes stock options and performances shares, which are granted annually but do not vest until a later date. Stock options vest over a three-year period, while performance shares vest based on Company total shareholder return relative to peers at the end of a three-year performance period. For stock options granted in 2014, the year-end stock price exceeded the grant price by 19%. Performance shares vested on December 31, 2014 for the 2012 through 2014 performance period at 14% of target value, reflecting the Company's lower total shareholder return relative to the performance share peer groups.

Compensation and Benefit Beliefs and Practices

The Company's compensation and benefit program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that the Company's executive compensation program should:

- Be competitive with the Company's industry peers;
- Motivate and reward achievement of the Company's goals;
- Be aligned with the interests of the Company's stockholders and its subsidiaries' customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of the Company's business goals. The Company believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for the Company's stockholders. Therefore, short-term performance pay is based on achievement of the Company's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by EPS performance. Long-term performance pay is tied to stockholder value, with 40% of the target value awarded in stock options, which reward stock price appreciation, and 60% awarded in performance shares, which reward total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Compensation Practices

- **Annual pay risk assessment** required by the Compensation Committee charter.
- Retention by the Compensation Committee of an **independent compensation consultant**, Pay Governance, that provides no other services to the Company.
- Inclusion of a **claw-back provision** that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- **No excise tax gross-up** on change-in-control severance arrangements.
- Provision of **limited ongoing perquisites** with no income tax gross-ups, except on certain relocation-related benefits
- "**No-hedging**" provision in the Company's insider trading policy that is applicable to all employees.
- **Strong stock ownership requirements** that are being met by all named executive officers.

Establishing Executive Compensation

The Compensation Committee establishes the executive compensation program. In doing so, the Compensation Committee uses information from others, principally Pay Governance. The Compensation Committee also relies on information from the Company's Human Resources staff and, for individual executive officer performance, from the Company's Chief Executive Officer. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on the Company's executive compensation at the 2014 Annual Meeting of Stockholders. In light of the significant support of the stockholders (94% of votes cast voting in favor of the proposal) and the actual payout levels of the performance-based compensation program, the Compensation Committee continues to believe that the Company's executive compensation program is competitive, aligned with the Company's financial and operational performance, and in the best interests of the Company, its stockholders, and its subsidiaries' customers.

Executive Compensation Focus

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

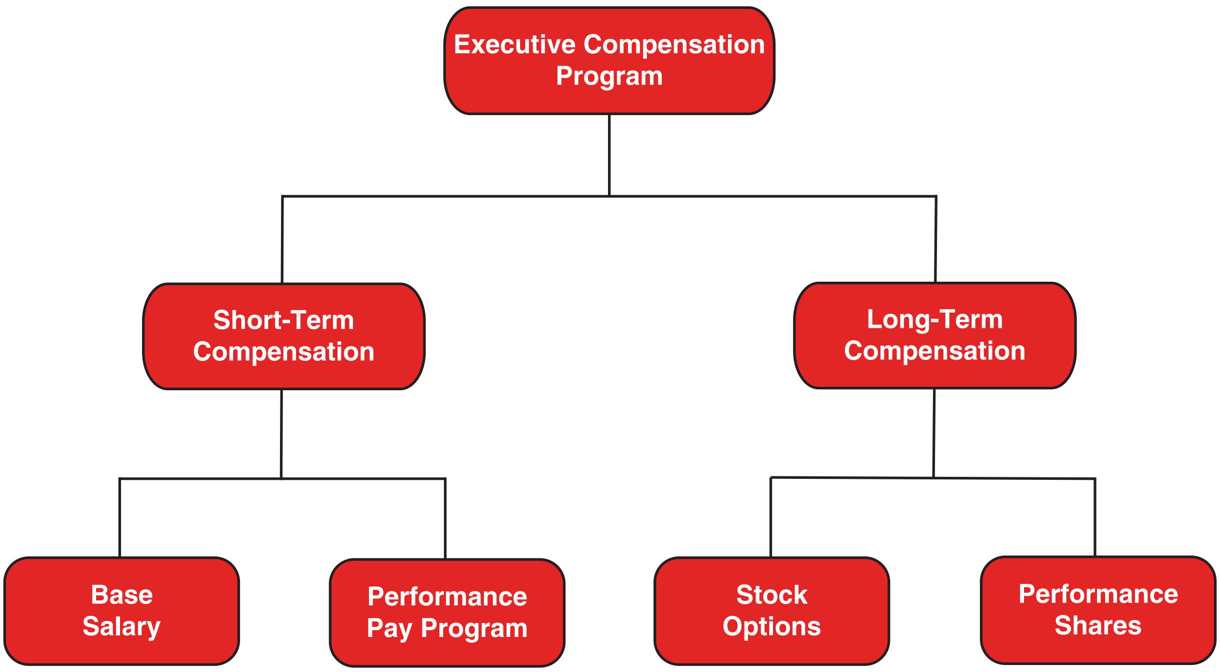
- Company EPS and business unit financial and operational performance, based on actual results compared to target performance levels established early in the year, determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Common Stock price changes result in higher or lower ultimate values of stock options.
- Total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, the Company has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control.

The pay-for-performance principles apply not only to the named executive officers but to thousands of employees. The Performance Pay Program covers almost all of the more than 26,000 employees of the Southern Company system. Stock options and performance shares were granted to approximately 3,800 employees of the Southern Company system. These programs engage employees, which ultimately is good not only for them, but also for the Company and its stockholders.

Overview of Executive Compensation Components

The primary components of the 2014 executive compensation program are shown below:



The Company's executive compensation program consists of a combination of short-term and long-term components. Short-term compensation includes base salary and the Performance Pay Program. Long-term performance-based compensation includes stock options, performance shares, and, in some cases, restricted stock units. The performance-based compensation components are linked to the Company's financial and operational performance, Common Stock performance, and total shareholder return. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent Directors. The Compensation Committee believes that the executive compensation program is a balanced program that provides market-based compensation and motivates and rewards performance.

Establishing Market-Based Compensation Levels

Pay Governance develops and presents to the Compensation Committee competitive market-based compensation levels for each of the named executive officers. The market-based compensation levels are developed from a size-appropriate energy services executive compensation survey database. The survey participants, listed below, are utilities with revenues greater than $6 billion. The Compensation Committee reviews the data and uses it in establishing market-based compensation levels for the named executive officers.

American Electric Power Company, Inc.	GDF SUEZ North America
Bg US Services, Inc.	Kinder Morgan, Inc.
Calpine Corporation	National Grid USA
CenterPoint Energy, Inc.	NextEra Energy, Inc.
CMS Energy Corporation	NRG Energy, Inc.
Consolidated Edison, Inc.	PG&E Corporation
Dominion Resources, Inc.	PPL Corporation
DTE Energy Company	Public Service Enterprise Group Inc.
Duke Energy Corporation	Sempra Energy
Edison International	Tennessee Valley Authority
Energy Transfer Partners, L.P.	The AES Corporation
Entergy Corporation	The Williams Companies, Inc.
Eversource Energy	UGI Corporation
Exelon Corporation	Xcel Energy Inc.
First Energy Corp.	

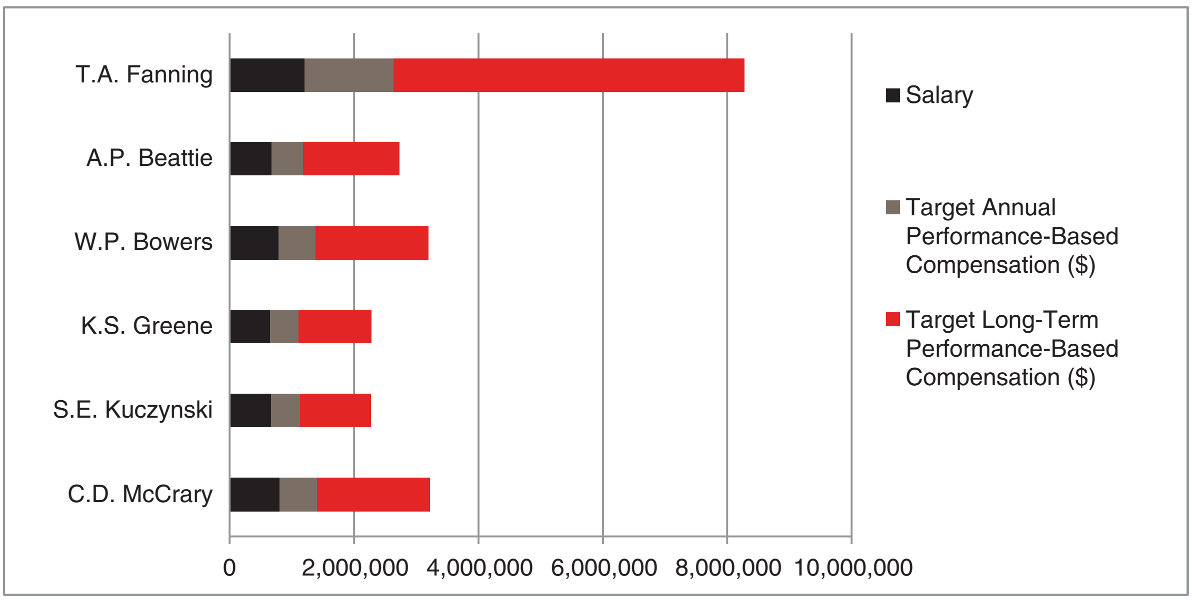
The Company is one of the largest utility holding companies in the United States based on revenues and market capitalization, and its largest business units are some of the largest in the industry as well. For that reason, Pay Governance uses size-appropriate survey market data in order to fit it to the scope of the Company's business.

Market data for the Chief Executive Officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed with the Compensation Committee. When appropriate, the market data is size-adjusted, up or down, to accurately reflect comparable scopes of responsibilities. Based on that data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, annual performance-based compensation at a target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given the Company's performance for the year or period.

A specified weight was not targeted for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2014 compensation amounts. Total target compensation opportunities for senior management as a group, including the named executive officers, are managed to be at the median of the market for companies of similar size in the electric utility industry. Therefore, some executives may be paid above and others below market. This practice allows for differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, differences are not considered to be material and the compensation program is believed to be market-appropriate, as long as senior management as a group is within an appropriate range. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data.

The Compensation Committee, working with Pay Governance, annually reviews the mix of key compensation components to assess the effectiveness of the executive compensation program in providing the appropriate levels of fixed and at-risk performance-based pay that is aligned with the Company's short- and long-term business strategies.

Based on this assessment, the Compensation Committee established the total target compensation opportunity in early 2014 for each named executive officer. The Compensation Committee believes that the compensation for the Company's officers, particularly the Chief Executive Officer and the other named executive officers, should be strongly tied to performance. As the chart below depicts, the fixed pay (base salary) for Mr. Fanning is only 14% of his total target compensation opportunity and ranges from 25% to 28% for the other named executive officers. Variable (at-risk) performance-based compensation is 86% for Mr. Fanning and 72% to 75% for the other named executive officers.



The salary levels shown above were not effective until March 2014. Therefore, the salary amounts reported in the Summary Compensation Table are different than the amounts shown above because that table reports actual amounts paid in 2014. The total target compensation opportunity amount shown for Mr. McCrary represents the full amount had he been employed the entire year by Alabama Power. However, the actual amounts Mr. McCrary received for salary and annual performance-based compensation were prorated based on the amount of time he was employed at Alabama Power in 2014. Additionally, the ultimate number of performance shares earned by Mr. McCrary will be prorated based on the time he was employed during the performance period. See the Summary Compensation Table and Grants of Plan-Based Awards in 2014 for more information on the actual compensation amounts Mr. McCrary received.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $2.20 per option and performance shares at $37.54 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted was 40% and 60%, respectively, of the long-term value shown above.

In 2013, Pay Governance analyzed the level of actual payouts for 2012 performance under the annual Performance Pay Program made to the named executive officers relative to performance versus peer companies to provide a check on the goal-setting process, including goal levels and associated performance-based pay opportunities. The findings from the analysis were used in establishing performance goals and the associated range of payouts for goal achievement for 2014. That analysis was updated in 2014 by Pay Governance for 2013 performance, and those findings were used in establishing goals for 2015.

Description of Key Compensation Components

2014 Base Salary

Base salary amounts for each of the named executive officers were recommended in 2014 for the Compensation Committee's approval by Mr. Fanning, except for his own salary. Those recommendations took into account the market data provided by Pay Governance, as well as the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the achievement of financial and operational goals in prior years. Based on these factors, most of the named executive officers received base salary increases in 2014, ranging from 1% to 4%, consistent with increases for most other employees.

2014 Performance-Based Compensation

This section describes performance-based compensation for 2014.

Achieving Operational and Financial Performance Goals — The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits the Company's stockholders in the short and long term. Operational excellence and business unit and Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2014, the Company strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices;
- Meeting energy demand with the best economic and environmental choices;
- Dividend growth;
- Long-term, risk-adjusted total shareholder return;
- Achieving net income goals to support the Southern Company financial plan and dividend growth; and
- Financial integrity — an attractive risk-adjusted return and sound financial policy.

The performance-based compensation program is designed to encourage achievement of these goals.

Mr. Fanning, with the assistance of the Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers (other than Mr. Fanning).

2014 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Rewards achievement of annual performance goals:
  - EPS
  - Business unit net income
  - Business unit operational performance
- Goals are weighted one-third each
- Performance results range from 0% to 200% of target, based on level of goal achievement
- Performance summary (as adjusted and described below): exceeded target performance
  - EPS: 176% of target
  - Corporate equity-weighted average net income result: 163% of target
  - Corporate weighted-average operational results: 172% of target

Overview of Program Design

Almost all employees of the Southern Company system, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee and include financial and operational goals. In setting the goals for pay purposes, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee, respectively. For more information on these committees' responsibilities, see the committee descriptions in this Proxy Statement.

- **Company Financial Goal: EPS**
  EPS is defined as the Company's net income from ongoing business activities divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.

- **Business Unit Financial Goal: Net Income**
  For the traditional operating companies (Alabama Power, Georgia Power, Gulf Power Company (Gulf Power), and Mississippi Power) and Southern Power, the business unit financial goal is net income. There is no separate net income goal set for the Company as a whole or for Southern Nuclear. Overall corporate performance is determined by the equity-weighted average of the business unit net income goal payouts. Payment for Southern Nuclear performance is based on the net income achievement of Alabama Power (50%) and Georgia Power (50%).

- **Business Unit Operational Goals: Varies by business unit**
  For most business units at the Company, including the traditional operating companies, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, major projects (Georgia Power and Mississippi Power), and culture. Southern Nuclear operational goals focus on safety, plant operations, major projects, and culture. Southern Power operational goals include safety, plant availability, and culture. Each of these operational goals is explained in more detail under Goal Details below. The level of achievement for each operational goal is determined according to the respective performance schedule, and the total operational goal performance is determined by the weighted average result.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial goals, such adjustments typically include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the financial goals were established and of sufficient magnitude to warrant recognition. As reported in the Company's 2014 Proxy Statement, the Compensation Committee did not follow its usual practice, and the charges taken in 2013 related to

Mississippi Power's construction of the integrated coal gasification combined cycle facility in Kemper County (Kemper IGCC) were not excluded from goal achievement results. Because the charges were not excluded, the payout levels for all employees, including the named executive officers, were reduced significantly in 2013. In 2014, the Company recorded pre-tax charges to earnings of $868 million ($536 million after-tax, or $0.59 per share) (2014 Kemper IGCC Charges) due to estimated probable losses relating to the Kemper IGCC. Additionally, Southern Company adjusted its 2014 net income by $17 million after-tax (or $0.02 per share) relating to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision that reversed the Mississippi Public Service Commission's March 2013 rate order associated with the Kemper IGCC (together with the 2014 Kemper IGCC Charges, 2014 Kemper IGCC Charges and Adjustments). The Compensation Committee reviewed the impact of the 2014 Kemper IGCC Charges and Adjustments on goal achievement and payout levels for all Southern Company system employees, including the named executive officers. The Compensation Committee determined that, given the action taken last year and the high levels of achievement of other performance goals in 2014, it was not appropriate to reduce payouts earned in 2014 under the broad-based program applicable to all participating employees. Therefore, the Compensation Committee made an adjustment to exclude the impact of the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) from earnings as it relates to the EPS goal payout for most Southern Company system employees.

As described in greater detail below in Calculating Payouts, Ms. Greene and Messrs. Fanning and Beattie are paid based on the equity-weighted average of the business unit net income results, which includes the net income goal achievement for Mississippi Power. Due to the 2014 Kemper IGCC Charges and Adjustments described above, Mississippi Power recorded a net loss of $328.7 million, resulting in below-threshold performance and would have resulted in no payout associated with the Mississippi Power portion of the net income goal for thousands of employees across the Southern Company system, including Ms. Greene and Messrs. Fanning and Beattie, as well as no payout at all for the business unit financial goal for all Mississippi Power employees. With the adjustment made by the Compensation Committee, Mississippi Power's net income for purposes of calculating goal achievement was $224 million. The adjusted net income resulted in a higher payout for the net income goal for all Mississippi Power employees as well as a higher payout associated with the overall equity-weighted average net income results for several thousand other employees across the Southern Company system whose payouts are determined by the equity-weighted average of the business unit net income results, including Ms. Greene and Messrs. Fanning and Beattie.

As described above, the adjustment to earnings as it relates to the EPS goal payout applied to employees across the entire Southern Company system, and the adjustment to Mississippi Power's net income goal achievement affected thousands of employees across the Southern Company system, including certain named executive officers. However, because the strategic goals related to the Kemper IGCC were not fully executed in 2014, the Compensation Committee determined that the final payout for certain executive officers most accountable for high-level strategic decisions concerning the Kemper IGCC, including some of the named executive officers, should be reduced from the amount they would have otherwise received. The Compensation Committee reduced payouts for Ms. Greene (25%) and Messrs. Fanning (30%), Beattie (10%), and Bowers (10%). See Calculating Payouts in this CD&A for a full description of how payouts were calculated for all of the named executive officers.

Under the terms of the program, no payout can be made if events occur that impact the Company's financial ability to fund the Common Stock dividend. The 2014 Kemper IGCC Charges and Adjustments described above did not have that effect.

Goal Details and 2014 Performance Results

Financial Performance Goals	Description	Why It Is Important
EPS	The Company's net income from ongoing business activities divided by average shares outstanding during the year.	Supports commitment to provide stockholders solid, risk-adjusted returns.
Business Unit Net Income	For the traditional operating companies and Southern Power, the business unit financial performance goal is net income after dividends on preferred and preference stock.	Supports delivery of stockholder value and contributes to the Company's sound financial policies and stable credit ratings.

The range of EPS and net income goals for 2014 is shown below. Overall corporate performance is determined by the equity-weighted average of the business unit net income goal payouts.

	EPS ($) (1)	Alabama Power ($, in millions)	Georgia Power ($, in millions)	Gulf Power ($, in millions)	Mississippi Power ($, in millions) (2)	Southern Power ($, in millions)	Corporate Equity-Weighted Average (2) (%)
Maximum	2.90	774.0	1,258.0	153.0	240.7	175.0	200
Target	2.76	717.0	1,160.0	140.2	218.6	135.0	100
Threshold	2.62	661.0	1,063.0	127.4	196.4	95.0	***
Results	2.80	760.6	1,225.0	140.2	224.0	172.3	163

(1) The EPS result shown in the table excludes the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) as described above. Therefore, payouts were determined using an EPS performance result that differed from the results reported in the Company's financial statements in the 2014 Annual Report attached as Appendix D to this Proxy Statement (Financial Statements). EPS, as determined in accordance with generally accepted accounting principles in the United States (GAAP) and as reported in the Financial Statements, was $2.19 per share.

(2) The corporate net income result is the equity-weighted average of the business unit net income results, including the net income result for Mississippi Power. Mississippi Power's net income result for this purpose was impacted by the adjustment for the 2014 Kemper IGCC Charges and Adjustments ($553 million on an after-tax basis). Therefore, payouts were determined using a net income performance result that differed from the results reported in the Financial Statements. Mississippi Power recorded a net loss, as determined in accordance with GAAP, of $328.7 million.

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional operating company, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affects customer satisfaction.
Reliability	Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.	Reliably delivering power to customers is essential to operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability are measured as a percentage of time the nuclear plant is operating. The reliability and availability metrics take generation reductions associated with planned outages into consideration.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
Major Projects – Plant Vogtle Units 3 and 4 and Kemper IGCC	The Southern Company system is committed to the safe, compliant, and high-quality construction and licensing of two new nuclear generating units under construction at Georgia Power's Plant Vogtle (Plant Vogtle Units 3 and 4) and the Kemper IGCC, as well as excellence in transition to operations and prudent decision-making related to these two major projects. An executive review committee is in place for each project to assess progress. A combination of subjective and objective measures is considered in assessing the degree of achievement. Final assessments for each project are approved by either the Company's Chief Executive Officer or the Company's Chief Operating Officer and confirmed by the Nuclear/Operations Committee.	Strategic projects enable the Southern Company system to expand capacity to provide clean, affordable energy to customers across the region.
Safety	The Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	Essential for the protection of employees, customers, and communities.
Culture	The culture goal seeks to improve the Company's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.	Supports workforce development efforts and helps to assure diversity of suppliers.

The ranges of performance levels established for the primary operational goals are detailed below, along with actual corporate results for 2014 performance.

Level of Performance	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operations	Safety	Plant Vogtle Units 3 and 4 and Kemper IGCC	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed targets	Industry best	Significantly exceed targets	Greater than 90th percentile or 5-year Company best	Significantly exceed targets	Significant improvement
Target	Top quartile overall	Meet targets	Top quartile	Meet targets	60th percentile	Meet targets	Improvement
Threshold	2nd quartile overall	Significantly below targets	2nd quartile	Significantly below targets	40th percentile	Significantly below targets	Significantly below expectations
Corporate Achievement	200%	195%	190%	150%	167%	Plant Vogtle: 175% Kemper IGCC: 75%	150%

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. If goal achievement is below threshold, there is no payout associated with the applicable goal.

Actual 2014 operational goal achievement is shown in the following tables.

Corporate (Ms. Greene and Messrs. Fanning and Beattie)

Company Corporate/Aggregate Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	195
Availability	190
Safety	167
Culture	150
Major Projects – Plant Vogtle Units 3 and 4 Assessment	175
Major Projects – Kemper IGCC Assessment	75
Total Operational Goal Performance Factor	172

Alabama Power (Mr. McCrary)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	177
Availability	200
Safety	165
Culture	130
Total Operational Goal Performance Factor	176

Georgia Power (Mr. Bowers)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	172
Availability	200
Safety	80
Major Projects – Plant Vogtle Units 3 and 4 Assessment	175
Culture	137
Total Operational Goal Performance Factor	162

Southern Nuclear (Mr. Kuczynski)

Goal	Achievement Percentage
Nuclear Safety	0
Plant Operations	150
Major Projects – Plant Vogtle Units 3 and 4 Assessment	175
Culture	131
Total Operational Goal Performance Factor	123

Calculating Payouts

Each named executive officer had a target Performance Pay Program opportunity, based on his or her position, set by the Compensation Committee at the beginning of 2014. Targets are set as a percentage of base salary.

All of the named executive officers are paid based on EPS performance. The business unit goals that determine payout levels vary based on the named executive officer's leadership role. For Ms. Greene and Messrs. Fanning and Beattie, payout is based on the equity-weighted average net income payout results for the traditional operating companies and Southern Power and the system-wide operational goal results. For Messrs. Bowers and McCrary, payout is based on achievement of the net income and operational goals of Georgia Power and Alabama Power, respectively. Mr. McCrary's payout is prorated based on the amount of time he was employed at Alabama Power during 2014. Mr. Kuczynski's payout is based on the achievement percentages of the net income goals of Alabama Power (50%) and Georgia Power (50%) and the Southern Nuclear operational goal results.

A total performance factor is determined by adding the EPS and applicable business unit financial and operational goal performance results and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity to determine the payout for each named executive officer. The table below shows the calculation of the total performance factor for each of the named executive officers, based on results shown above.

	Southern Company EPS Result (%) 1/3 weight (1)	Business Unit Financial Goal Result (%) 1/3 weight (1)	Business Unit Operational Goal Result (%) 1/3 weight	Total Performance Factor (%)
T. A. Fanning	176	163	172	170
A. P. Beattie	176	163	172	170
W. P. Bowers	176	166	162	168
K. S. Greene	176	163	172	170
S. E. Kuczynski	176	171	123	157
C. D. McCrary	176	176	176	176

(1) Excluding impact of the 2014 Kemper IGCC Charges and Adjustments.

The table below shows the pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity (%)	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%) (1)	Actual Annual Performance Pay Program Payout ($) (2)
T. A. Fanning	120	1,440,000	170	1,713,600
A. P. Beattie	75	505,123	170	772,839
W. P. Bowers	75	590,503	168	892,841
K. S. Greene	70	455,000	170	580,125
S. E. Kuczynski	70	467,875	157	734,564
C. D. McCrary (3)	75	602,435	176	333,990

(1) Shown as modified and described above.

(2) As described above, the Compensation Committee reduced the final payouts for Ms. Greene (25%) and Messrs. Fanning (30%), Beattie (10%), and Bowers (10%) after the adjustments to performance results in connection with the 2014 Kemper IGCC Charges and Adjustments.

(3) Mr. McCrary retired from Alabama Power effective May 1, 2014; therefore, his Performance Pay Program payout was prorated based on the amount of time he was employed in 2014. The target amount shown is his full target opportunity as if he had been employed for the entire year. The actual amount shown is the prorated amount Mr. McCrary received.

Long-Term Performance-Based Compensation

2014 Long-Term Pay Program Highlights

- Stock Options:
  - Reward long-term Common Stock price appreciation
  - Represent 40% of long-term target value
  - Vest over three years
  - Ten-year term
- Performance Shares:
  - Reward total shareholder return relative to industry peers and stock price appreciation
  - Represent 60% of long-term target value
  - Three-year performance period
  - Performance results can range from 0% to 200% of target
  - Paid in Common Stock at end of performance period
- Restricted Stock Units
  - Used to promote retention of key employees or to attract key employees by replacing award values forfeited upon leaving a former employer
  - Continued employment until vesting date(s) is required
  - Paid in Common Stock upon vesting
- Performance Summary:
  - Stock options: for options granted in 2014, year-end stock price exceeded option exercise price by nearly 19%
  - Performance shares: paid out at 14% of target
  - Restricted stock units: one new grant in 2014 to Mr. Kuczynski

Long-term performance-based awards are intended to promote long-term success and increase stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of stockholders. Long-term performance-based awards also benefit the Southern Company system's customers by providing competitive compensation that allows the Southern Company system to attract, retain, and engage employees who provide focus on serving customers and delivering safe and reliable electric service.

Stock options represent 40% of the long-term performance target value, and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Stock options only generate value if the price of the stock appreciates after the grant date, and performance shares reward employees based on Southern Company's total shareholder return relative to industry peers, as well as Common Stock price. The Compensation Committee also awards restricted stock units occasionally, typically as retention awards or to attract key employees by replacing the value of awards that are forfeited upon leaving a former employer.

The following table shows the grant date fair value of the long-term performance-based awards granted in 2014, except restricted stock units.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
T. A. Fanning	2,255,999	3,383,968	5,639,967
A. P. Beattie	619,617	929,415	1,549,032
W. P. Bowers	724,350	1,086,520	1,810,870
K. S. Greene	467,999	701,998	1,169,997
S. E. Kuczynski	454,507	681,726	1,136,233
C. D. McCrary	722,920	1,084,380	1,807,300

Stock Options

Stock options granted have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. For the grants made in 2014, unvested options are forfeited if the named executive officer retires from the Southern Company system and accepts a position with a peer company within two years of retirement. The grants made to Mr. McCrary in 2014 vested upon his retirement; however, he will forfeit those options that vested upon retirement if he accepts a position with a peer company within two years of his retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the Financial Statements. For 2014, the Black-Scholes value on the grant date was $2.20 per stock option, and the exercise price is $41.28.

Performance Shares

2014-2016 Grant

Performance shares are denominated in units, meaning no actual shares are issued on the grant date. A grant date fair value per unit was determined. For the grant made in 2014, the value per unit was $37.54. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock.

At the end of the three-year performance period (January 1, 2014 through December 31, 2016), the number of units will be adjusted up or down (0% to 200%) based on the Company's total shareholder return relative to that of its peers in a custom peer group. While in previous years the Company's total shareholder return was measured relative to two peer groups (a custom peer group and the Philadelphia Utility Index), the Compensation Committee decided to streamline the performance share peer group for the 2014 grant by eliminating the Philadelphia Utility Index and establishing one custom peer group. The companies in the custom peer group are those that are believed to be most similar to the Company in both business model and investors, creating a peer group that is even more aligned with the Company's strategy. For performance shares granted in previous years using the dual peer group structure, the final result will be measured using both peer groups as approved by the Compensation Committee at the time of the grant. The custom peer group varies from the Market Data peer group discussed previously due to the timing and criteria of the peer selection process; however, there is significant overlap. The number of performance share units earned will be paid in Common Stock at the end of the three-year performance period. No dividends or dividend equivalents will be paid or earned on the performance share units.

The companies in the custom peer group on the grant date are listed in the following table.

Alliant Energy Corporation	Integrys Energy Group
Ameren Corporation	Pepco Holdings, Inc.
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	PPL Corporation
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Wisconsin Energy Corporation
Edison International	Xcel Energy Inc.
Eversource Energy	

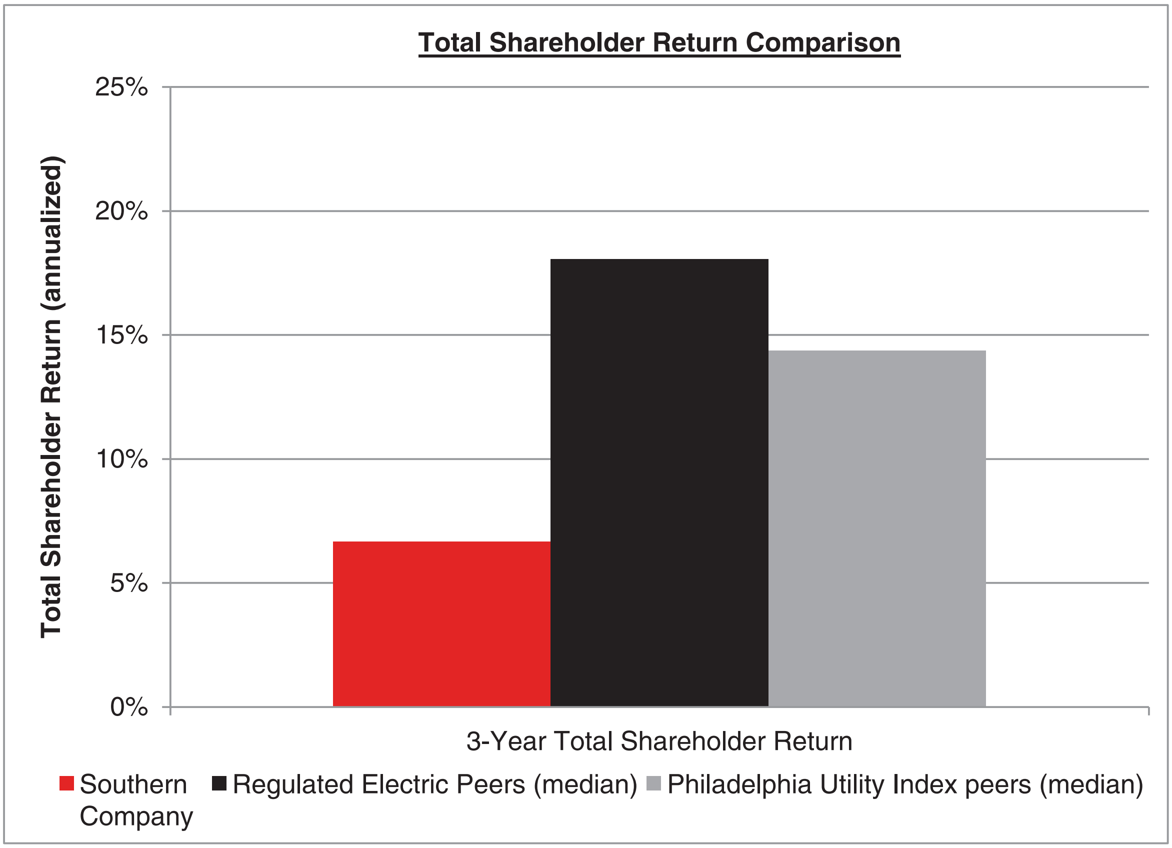
The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2014 through 2016 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher (Maximum)	200
50th percentile (Target)	100
10th percentile (Threshold)	0

Performance shares are not earned until the end of the three-year performance period. A participant who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

2012-2014 Payouts

Performance share grants were made in 2012 with a three-year performance period that ended on December 31, 2014. Based on the Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (28% payout) and the custom peer group (0% payout) as shown in the chart below, the payout percentage was 14% of target, which is the average of the two peer groups.



The following table shows the target and actual awards of performance shares for the named executive officers. Actual payouts were significantly below the target grant value due to lower relative total shareholder return.

	Target Performance Shares (#)	Target Value of Performance Shares ($)	Performance Shares Earned (#)	Value of Performance Shares Earned ($)
T. A. Fanning	72,338	3,037,473	10,127	497,337
A. P. Beattie	18,417	773,330	2,578	126,606
W. P. Bowers	23,906	1,003,813	3,347	164,371
K. S. Greene (1)	0	0	0	0
S. E. Kuczynski	14,717	617,967	2,060	101,167
C. D. McCrary (2)	25,121	1,054,831	2,735	134,316

(1) Ms. Greene was not employed by the Southern Company system when the Compensation Committee granted performance shares in 2012.

(2) The number of performance shares earned by Mr. McCrary is prorated based on the time he was employed by Alabama Power during the performance period.

Restricted Stock Units

In limited situations, restricted stock units are granted to address specific needs, including retention. These awards serve two primary purposes. They further align the recipient's interests with those of the Company's stockholders, and they provide strong retention value. For information on treatment upon termination or change in control, see Potential Payments Upon Termination or Change-in-Control.

In October 2014, the Compensation Committee granted Mr. Kuczynski restricted stock units valued at $1,000,016 on the grant date that will vest in October 2017 if he remains employed with the Southern Company system through the vesting date. The Compensation Committee believes that, given Mr. Kuczynski's expertise and the competitiveness of the nuclear labor market, there is a retention risk and, therefore, providing a retention award was in the best interest of the Company. The Compensation Committee sought advice from Pay Governance in determining market practice and the appropriate value of the award.

Restricted stock units were granted to Ms. Greene in 2013 and will vest incrementally each year starting April 1, 2015 and ending April 1, 2018 if she remains employed with the Southern Company system.

Restricted stock units were granted to Mr. McCrary in 2012 with a vesting date of December 31, 2014 in order to retain Mr. McCrary until his successor was named and expiration of an appropriate transition period. Mr. McCrary's successor was announced in February 2014, and Mr. McCrary retired effective May 1, 2014. The Compensation Committee modified the vesting date to April 30, 2014.

See the Summary Compensation Table, the Grants of Plan-Based Awards table, the Outstanding Equity Awards at 2014 Fiscal Year End table, and accompanying information for more information on restricted stock unit awards.

Timing of Performance-Based Compensation

As discussed above, the 2014 annual Performance Pay Program goals and the total shareholder return goals applicable to performance shares were established early in the year by the Compensation Committee. Annual stock option grants also were made by the Compensation Committee. The establishment of performance-based compensation goals and the granting of equity awards were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2014 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers, consistent with the Company's goal of providing market-based compensation and benefits.

Retirement Benefits

Generally, all full-time employees of the Southern Company system participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The Company also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information.

The Company also provides the Deferred Compensation Plan, which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and accompanying information for more information about the Deferred Compensation Plan.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of the Company coupled with an involuntary termination not for cause or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; *i.e.*, there must be both a change in control and a termination of employment. Severance payment amounts are two times salary plus target Performance Pay Program opportunity for the named executive officers, except for Mr. Fanning whose severance payment amount is three times salary plus Performance Pay Program target opportunity. No excise tax gross-up would be provided. Change-in-control protections allow executive officers to focus on potential transactions that are in the best interest of shareholders. More information about severance arrangements is included under Potential Payments upon Termination or Change-in-Control.

Perquisites

The Company provides limited ongoing perquisites to its executive officers, including the named executive officers, consistent with the Company's goal of providing market-based compensation and benefits. The perquisites provided in 2014, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites, except on certain relocation-related benefits.

Performance-Based Compensation Program Changes for 2015

In early 2015, the Compensation Committee made several changes to the Company's performance-based compensation programs, impacting 2015 compensation. These changes affect both the annual Performance Pay Program as well as the long-term performance-based compensation program and are described below.

Annual Performance-Based Pay Program

Beginning in 2015, the annual performance-based pay program will incorporate individual goals for all executive officers of the Company. Currently, the goals are equally weighted between the EPS goal, the applicable business unit net income goal, and the applicable business unit operational goals. Starting with the 2015 annual Performance Pay Program goals, the Compensation Committee eliminated the business unit net income goal for the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), added an individual goal component, and changed the weights for the EPS goal and operational goals. All other executive officers will now have four goals: EPS, business unit net income, business unit operational goals, and their individual goals. The table below outlines the new weights for each goal.

	EPS	Net Income	Operational	Individual
CEO and CFO	40%	0%	30%	30%
All other executive officers	30%	30%	30%	10%

Long-Term Performance-Based Compensation

Since 2010, the Company's long-term performance-based compensation program has included two components: stock options and performance shares. After reviewing current market practices with Pay Governance, the Compensation Committee decided to modify the Company's long-term performance-based compensation program to further align the Company's compensation program with its peers in the utility industry and create better alignment of pay with long-term Company performance. Beginning with long-term performance-based equity grants made in early 2015, the long-term performance-based program consists exclusively of performance shares. The new structure maintains the three-year performance cycle described earlier in this CD&A for performance shares but expands the performance metrics from one (relative total shareholder return) to three metrics. The new program now includes relative total shareholder return (50%), cumulative EPS from ongoing operations over a three-year period (25%), and equity-weighted return on equity (ROE) (25%). Under the new program, dividends will accrue on performance shares throughout the performance period, and eligible new hires and newly promoted employees will receive interim prorated grants of performance shares instead of stock options.

The continued use of relative total shareholder return as a metric in the long-term performance program maintains consistency with the previous program as well as allows the Company to measure its performance against a custom group of regulated peers. The new EPS goal measures cumulative EPS from ongoing operations over a three-year period and motivates ongoing earnings growth to support the Company's dividend and achievement of strategic financial objectives. The new equity-weighted ROE goal measures traditional operating company performance from ongoing operations over a three-year period and is set to encourage top quartile ROE performance. Both the EPS and ROE goals are subject to a gateway goal focused on the Company's credit ratings. If the Company fails to meet the credit rating requirements established by the Compensation Committee, there will be no payout associated with the EPS and ROE goals.

Executive Stock Ownership Requirements

Officers of the Company and its subsidiaries that are in a position of Vice President or above are subject to stock ownership requirements. All of the named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and stockholders by promoting a long-term focus and long-term share ownership.

The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60. Mr. Beattie is 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
T. A. Fanning	5 Times	10 Times
A. P. Beattie	1.5 Times	3 Times
W. P. Bowers	3 Times	6 Times
K. S. Greene	3 Times	6 Times
S. E. Kuczynski	3 Times	6 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement. Newly-promoted officers have approximately five years from the date of their promotion to meet the increased ownership requirement. All of the named executive officers are meeting their respective ownership requirements. Mr. McCrary retired and is therefore no longer subject to stock ownership requirements.

Impact of Accounting and Tax Treatments on Compensation

Section 162(m) of the Internal Revenue Code of 1986, as amended (Code), limits the tax deductibility of the compensation of the named executive officers, except Messrs. Beattie and McCrary, that exceeds $1 million per year unless the compensation is paid under a performance-based plan as defined in the Code that has been approved by stockholders. The Company has obtained stockholder approval of the Omnibus Incentive Compensation Plan, under which most of the performance-based compensation is paid. Because the Company's policy is to maximize long-term stockholder value, as described fully in this CD&A, tax deductibility is not the only factor considered in setting compensation. The Compensation Committee has the discretion to award compensation that may not be tax deductible.

The Compensation Committee approved a formula in February 2014 that represented a maximum annual performance-based compensation amount payable to the affected named executive officers. For 2014 performance, the Compensation Committee used negative discretion from the approved formula amount to determine the actual payouts for the affected named executive officers under the annual performance-based compensation program pursuant to the methodologies described above.

Policy on Recovery of Awards

The Company's Omnibus Incentive Compensation Plan provides that, if the Company is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of the Company knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer must repay the Company the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

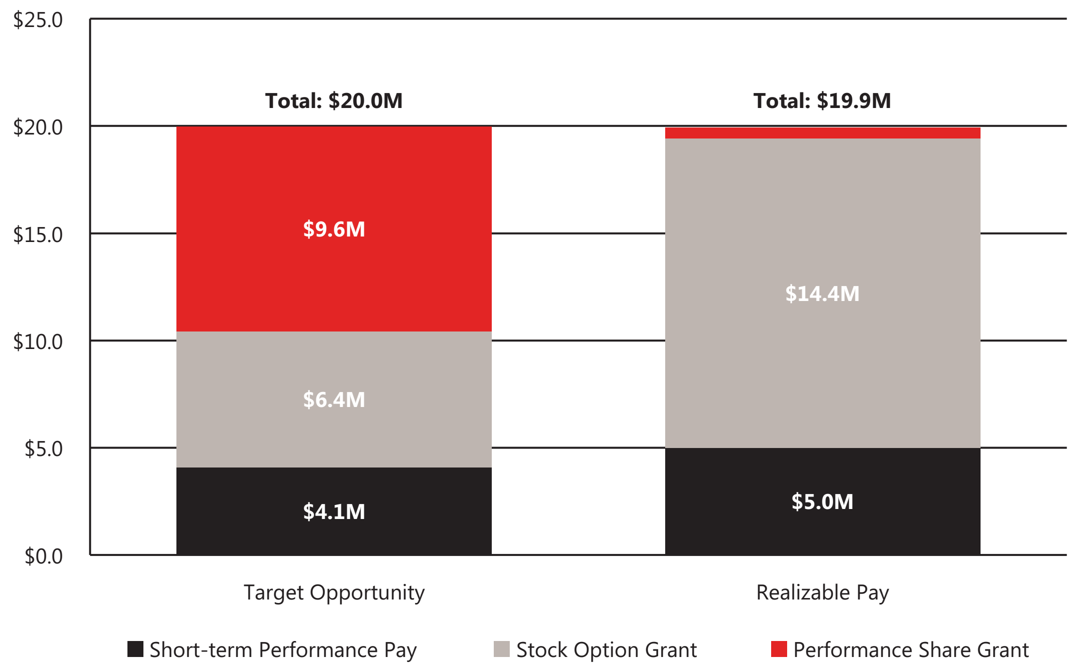
Policy Regarding Hedging the Economic Risk of Stock Ownership

The Company's policy is that employees and outside Directors will not trade Company options on the options market and will not engage in short sales.

Realizable Performance-Based Compensation Analysis

The SEC has promulgated rules regarding how total compensation is calculated in the Summary Compensation Table. These rules include accounting assumptions that affect the value reported for equity grants. However, as the Company's performance changes over time, the Common Stock price can fluctuate, affecting the value of equity grants made to the named executive officers. The Compensation Committee believes it is important to look at those changes to fully understand the value of the compensation received because the reported value is only realized if the Company meets certain performance criteria. In order to supplement the SEC-required disclosure, the chart below compares the target or grant date value of performance-based compensation granted to Mr. Fanning in 2012, 2013, and 2014 with the value actually received or as measured on December 31, 2014.

CEO Target vs. Realizable Pay



The realizable amount shown for short-term performance pay includes the actual amount paid to Mr. Fanning for 2012, 2013, and 2014 under the Performance Pay Program.

The realizable amount shown for stock options includes the intrinsic value of all stock options granted to Mr. Fanning in 2012, 2013, and 2014 calculated using the Common Stock closing price on December 31, 2014. This amount is subject to change based on changes in the Common Stock price.

The realizable amount shown for performance shares includes the value Mr. Fanning received based on the payout of the performance shares granted in 2012 for the 2012 through 2014 performance period as well as the projected amounts based on performance levels relative to peers as of December 31, 2014 for the 2013 and 2014 grants. This amount is subject to change based on the Company's performance relative to its peers at the end of the applicable three-year performance period. See Performance Shares in this CD&A for a description of the Company's performance share peer group.

COMPENSATION AND MANAGEMENT SUCCESSION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Board of Directors that the CD&A be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2014 and in this Proxy Statement. The Board of Directors approved that recommendation.

Members of the Compensation Committee:

Henry A. Clark III, Chair
David J. Grain
Veronica M. Hagen
William G. Smith, Jr.
Steven R. Specker

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2012, 2013, and 2014 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
Thomas A. Fanning	2014	1,192,067	—	3,383,968	2,255,999	1,713,600	2,899,537	70,822	11,515,993
Chairman, President,	2013	1,152,389	—	3,128,625	2,085,747	1,199,307	805,738	66,485	8,438,291
and Chief Executive Officer	2012	1,114,846	—	3,037,473	2,025,000	2,078,158	4,712,413	67,458	13,035,348
Art P. Beattie	2014	668,516	—	929,415	619,617	772,839	1,396,842	37,293	4,424,522
Executive Vice	2013	644,039	—	796,514	531,025	437,126	402,101	122,037	2,932,842
President and Chief Financial Officer	2012	615,378	—	773,330	515,558	737,382	2,747,374	34,352	5,423,374
W. Paul Bowers	2014	782,928	45	1,086,520	724,350	892,841	1,504,316	46,986	5,037,986
Chairman, President,	2013	760,482	—	1,031,940	687,964	498,775	—	44,375	3,023,536
and Chief Executive Officer, Georgia Power	2012	739,587	42	1,003,813	669,227	1,013,366	2,024,578	50,830	5,501,443
Kimberly S. Greene	2014	650,000	—	701,998	467,999	580,125	326,334	605,315	3,331,771
Executive Vice President and Chief Operating Officer	2013	475,000	—	2,000,005	1,039,997	310,811	212,666	656,035	4,694,514
Stephen E. Kuczynski	2014	667,120	—	1,681,742	454,507	734,564	217,633	39,117	3,794,683
President and Chief	2013	658,378	—	635,283	423,534	426,183	126,714	42,692	2,312,784
Executive Officer, Southern Nuclear	2012	640,289	—	617,967	411,997	619,288	77,727	101,886	2,469,154
Charles D. McCrary Former Chairman,	2014	389,266	—	2,896,902	722,920	333,990	923,064	96,937	5,363,079
President, and	2013	799,124	—	1,084,347	722,922	650,630	414,103	45,396	3,716,522
Chief Executive Officer, Alabama Power	2012	777,167	—	3,054,840	703,232	1,028,204	2,437,448	44,722	8,045,613

Column (a)

Ms. Greene was not an executive officer of the Company prior to 2013.

Column (d)

This amount shown for Mr. Bowers reflects the value of a non-cash safety award for Mr. Bowers. All employees of Georgia Power with a perfect individual safety record in 2014 received the award.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2014. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2014. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2016. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2014 to Ms. Greene and Messrs. Fanning, Beattie, Bowers, and Kuczynski, assuming that the highest level of performance is achieved, is $1,403,996, $6,767,936, $1,858,830, $2,173,040, and $1,363,453, respectively (200% of the amount shown in the table). Because Mr. McCrary retired from Alabama Power effective May 1, 2014, the maximum amount he could earn is $241,007, which is prorated based on the number of months he was employed during the performance period. The amount reflected in column (e) for Mr. McCrary also includes the incremental fair value related to the modification of the vesting date of the restricted stock units granted to Mr. McCrary in 2012 and discussed in the CD&A. See Note 8 to the Financial Statements for a discussion of the assumptions used in calculating these amounts.

Column (f)

This column reports the aggregate grant date fair value of stock options granted in the applicable year. See Note 8 to the Financial Statements for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the payouts under the annual Performance Pay Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended on December 31, 2014. The Performance Pay Program is described in detail in the CD&A.

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31, 2012, 2013, and 2014. Because Mr. McCrary retired in 2014, the amount reported for him in 2014 reflects the actual benefits expected to be paid after the measurement date. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions the Company selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at the Company or any Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates. In general, pension values increased for all named executive officers due to a decrease in discount rates and updated mortality rates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2014, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2013 and December 31, 2014 are:

- Discount rate for the Pension Plan was decreased to 4.20% as of December 31, 2014 from 5.05% as of December 31, 2013;
- Discount rate for the supplemental pension plans was decreased to 3.75% as of December 31, 2014 from 4.50% as of December 31, 2013; and
- Mortality rates for all plans were updated due to the release of new mortality tables.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; tax reimbursements on certain relocation-related benefits and retirement-related financial planning assistance; employer contributions in 2014 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Code; and contributions in 2014 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported for 2014 are itemized below.

	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
T. A. Fanning	10,023	—	13,260	47,539	70,822
A. P. Beattie	5,022	—	11,437	20,834	37,293
W. P. Bowers	7,464	—	12,853	26,669	46,986
K. S. Greene	400,708	171,457	13,260	19,890	605,315
S. E. Kuczynski	9,241	—	9,113	20,763	39,117
C. D. McCrary	84,345	—	11,199	1,393	96,937

Description of Perquisites

Personal Financial Planning is provided for most officers of the Company, including all of the named executive officers. The Company pays for the services of a financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. The Company also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits are provided to cover the costs associated with geographic relocation. In 2014, Ms. Greene received relocation-related benefits in the amount of $363,155 in connection with her 2014 relocation from Atlanta, Georgia to Birmingham, Alabama. This amount was for the shipment of household goods, incidental expenses related to her move, and home sale and home repurchase assistance. Also, as provided in the Company's relocation policy, tax assistance is provided on the taxable relocation benefits. If Ms. Greene terminates within two years of her relocation, these amounts must be repaid.

Personal Use of Corporate Aircraft. The Southern Company system has aircraft that are used to facilitate business travel. All flights on these aircraft must have a business purpose, except limited personal use that is associated with business travel is permitted. The amount reported for such personal use is the incremental cost of providing the benefit, primarily fuel costs. Also, if seating is available, the Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel, and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included. The perquisite amount shown above for Mr. Bowers includes $1,664 for approved personal use of corporate aircraft. In connection with Ms. Greene's relocation, the Compensation Committee approved personal use of the corporate aircraft for weekly round-trip flights between Atlanta and Birmingham for the first twelve months following her relocation to Birmingham. The perquisite amount shown above for Ms. Greene includes $32,379 for this approved personal use of corporate aircraft.

Other Miscellaneous Perquisites. The amount included reflects the full cost to the Company of providing the following items: personal use of Company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at Company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2014

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2014 by the Compensation Committee.

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($) (l)
		Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (h)	Target (#) (g)	Maximum (#) (h)				
T. A. Fanning		14,400	1,440,000	2,880,000							
	2/10/2014				901	90,143	180,286				3,383,968
	2/10/2014								1,025,454	41.28	2,255,999
A. P. Beattie		5,051	505,123	1,010,247							
	2/10/2014				247	24,758	49,516				929,415
	2/10/2014								281,644	41.28	619,617
W. P. Bowers		5,905	590,503	1,181,007							
	2/10/2014				289	28,943	57,886				1,086,520
	2/10/2014								329,250	41.28	724,350
K. S. Greene		4,550	455,000	910,000							
	2/10/2014				187	18,700	37,400				701,998
	2/10/2014								212,727	41.28	467,999
S. E. Kuczynski		4,679	467,875	935,750							
	2/10/2014				181	18,160	36,320				681,726
	2/10/2014								206,594	41.28	454,507
	10/20/2014							21,377			1,000,016
C. D. McCrary		1,898	189,767	379,534							
	2/10/2014				288	28,886	57,772				1,084,380
	2/10/2014								328,600	41.28	722,920
	2/10/2014							43,908			1,812,522

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2014 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table. The amounts shown for Mr. McCrary are prorated based on the amount of time he was employed at Alabama Power in 2014.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2014, as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2014 through 2016 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

The number of shares shown for Mr. McCrary reflects the full grant he received in February

2014. However, since Mr. McCrary retired in May 2014, the ultimate number of performance shares he will receive will be prorated based on the number of months he was employed by Alabama Power during the performance period.

Column (i)

This column reflects the number of restricted stock units granted to Mr. Kuczynski on the grant date as described in the CD&A. This column also reflects the restricted stock units granted to Mr. McCrary in 2012 and modified by the Compensation Committee in February 2014, as described in the CD&A.

Columns (j) and (k)

Column (j) reflects the number of stock options granted to the named executive officers in 2014, as described in the CD&A, and column (k) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (l)

This column reflects the aggregate grant date fair value of the performance shares, stock options, and restricted stock units granted in 2014. This column also reflects the incremental fair value of the restricted stock units granted to Mr. McCrary in 2012 and modified in February 2014. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model. For the restricted stock units granted to Mr. Kuczynski, the value is based on the closing price of Common Stock on the grant date. According to SEC rules, the incremental fair value of the restricted stock units granted to Mr. McCrary in 2012 and modified in February 2014 is reported using the value on the modification date. The assumptions used in calculating these amounts are discussed in Note 8 to the Financial Statements.

OUTSTANDING EQUITY AWARDS AT 2014 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares and restricted stock units) held by or granted to the named executive officers as of December 31, 2014.

	Option Awards				Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Number of Shares or Units of Stock That Have Not Vested (#) (f)	Market Value of Shares or Units of Stock That Have Not Vested ($) (g)	Equity Incentive Plan Awards: Number of Unearned Shares, Units, or Other Rights That Have Not Vested (#) (h)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units, or Other Rights That Have Not Vested ($) (i)
T. A. Fanning	398,230	199,115	44.42	2/13/2022				
	238,099	476,198	44.06	2/11/2023				
	—	1,025,454	41.28	2/10/2024				
							77,250	3,793,748
							90,143	4,426,923
A. P. Beattie	140,384	—	37.97	2/14/2021				
	101,388	50,694	44.42	2/13/2022				
	60,620	121,238	44.06	2/11/2023				
	—	281,644	41.28	2/10/2024				
							19,667	965,846
							24,758	1,215,865
W. P. Bowers	70,680	—	36.42	2/19/2017				
	85,151	—	35.78	2/18/2018				
	90,942	—	31.39	2/16/2019				
	233,477	—	31.17	2/15/2020				
	164,377	—	37.97	2/14/2021				
	131,608	65,804	44.42	2/13/2022				
	78,535	157,069	44.06	2/11/2023				
	—	329,250	41.28	2/10/2024				
							25,480	1,251,323
							28,943	1,421,391
K. S. Greene	109,705	219,408	46.74	4/1/2023				
	—	212,727	41.28	2/10/2024				
							18,700	918,357
					46,425	2,279,932		
S. E. Kuczynski	332,225	—	40.14	7/11/2021				
	81,022	40,511	44.42	2/13/2022				
	48,349	96,697	44.06	2/11/2023				
	—	206,594	41.28	2/10/2024				
							15,686	770,339
							18,160	891,838
					30,931	1,519,021		
C. D. McCrary	207,443	—	44.42	2/13/2022				
	247,576	—	44.06	2/11/2023				
	328,600	—	41.28	2/10/2024				
							26,774	1,314,871
							28,886	1,418,591

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2007 through 2011 with expiration dates from 2017 through 2021 were fully vested as of December 31, 2014. The options granted in 2012, 2013, and 2014 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2012	February 13, 2022	February 13, 2015
2013	February 11, 2023	February 11, 2016
2014	February 10, 2024	February 10, 2017

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments upon Termination or Change-in-Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

These columns reflect the number of restricted stock units, including the deemed reinvestment of dividends, held as of December 31, 2014. The value in column (g) is based on the Common Stock closing price on December 31, 2014 ($49.11). The restricted stock units for Ms. Greene vest incrementally each year starting April 1, 2015 and ending April 1, 2018 if she remains employed with the Southern Company system. The restricted stock units for Mr. Kuczynski vest on December 31, 2017 if he remains employed with the Southern Company system on the vesting date. See further discussion of restricted stock units in the CD&A. See also Potential Payments upon Termination or Change-in-Control for more information about the treatment of restricted stock units under different termination and change-in-control events.

Columns (h) and (i)

In accordance with SEC rules, column (h) reflects the target number of performance shares that can be earned at the end of each three-year performance period (December 31, 2015 and 2016) that were granted in 2013 and 2014, respectively. The performance shares granted for the 2012 through 2014 performance period vested on December 31, 2014 and are shown in the Option Exercises and Stock Vested in 2014 table below.

The value in column (i) is derived by multiplying the number of shares in column (h) by the Common Stock closing price on December 31, 2014 ($49.11). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. The ultimate number of shares earned by Mr. McCrary will be prorated based on the number of months he was employed by Alabama Power during the performance periods. See further discussion of performance shares in the CD&A. See also Potential Payments upon Termination or Change-in-Control for more information about the treatment of performance shares under different termination and change-in-control events.

OPTION EXERCISES AND STOCK VESTED IN 2014

Name (a)	Option Awards: Number of Shares Acquired on Exercise (#) (b)	Option Awards: Value Realized on Exercise ($) (c)	Stock Awards: Number of Shares Acquired on Vesting (#) (d)	Stock Awards: Value Realized on Vesting ($) (e)
T. A. Fanning	1,049,185	10,336,745	10,127	497,337
A. P. Beattie	57,983	547,091	2,578	126,606
W. P. Bowers	128,093	1,628,963	3,347	164,371
K. S. Greene	—	—	—	—
S. E. Kuczynski	—	—	2,060	101,167
C. D. McCrary	452,498	4,169,084	50,311	2,314,724

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2014, and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

Columns (d) and (e)

Column (d) includes the performance shares awarded for the 2012 through 2014 performance period that vested on December 31, 2014. The value reflected in column (e) is derived by multiplying the number of shares that vested by the market value of the underlying shares on the vesting date ($49.11).

Because Ms. Greene was not an employee of the Southern Company system when performance shares were awarded in 2012, column (d) does not reflect any vested performance shares for her.

Certain restricted stock units with reinvested dividends vested on April 30, 2014 and are reflected in column (d) for Mr. McCrary. The value of the restricted stock units as shown in column (e) is derived by multiplying the number of restricted stock units and reinvested dividends that vested (47,576) by the market value of the underlying shares on the vesting date ($45.83).

PENSION BENEFITS AT 2014 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
T. A. Fanning	Pension Plan	33.0	1,359,877	—
	Supplemental Benefit Plan (Pension-Related)	33.0	10,947,004	—
	Supplemental Executive Retirement Plan	33.0	4,468,682	—
A. P. Beattie	Pension Plan	37.92	1,737,633	—
	Supplemental Benefit Plan (Pension-Related)	37.92	5,206,128	—
	Supplemental Executive Retirement Plan	37.92	2,011,301	—
W. P. Bowers	Pension Plan	34.67	1,445,025	—
	Supplemental Benefit Plan (Pension-Related)	34.67	5,671,484	—
	Supplemental Executive Retirement Plan	34.67	1,860,971	—
K. S. Greene	Pension Plan	7.17	203,653	—
	Supplemental Benefit Plan (Pension-Related)	7.17	192,443	—
	Supplemental Executive Retirement Plan	7.17	255,522	—
S. E. Kuczynski	Pension Plan	2.58	89,419	—
	Supplemental Benefit Plan (Pension-Related)	2.58	223,065	—
	Supplemental Executive Retirement Plan	2.58	109,590	—
C. D. McCrary	Pension Plan	39.33	1,931,424	77,806
	Supplemental Benefit Plan (Pension-Related)	39.33	8,522,909	920,251
	Supplemental Executive Retirement Plan	39.33	2,688,067	290,241

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is the Company's primary retirement plan. Generally, all full-time Southern Company system employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The rates of pay considered for this formula are the base salary rates with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2014 was $260,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation earned each year is added to the base salary rates.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2014, all of the named executive officers are retirement-eligible except Ms. Greene and Mr. Kuczynski.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. As of December 31, 2014, all of the named executive officers are vested in their Pension Plan benefits except Mr. Kuczynski. Ms. Greene received years of credited service for her previous employment with the Southern Company system. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50. After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal Pension Plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When a SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent.

Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement-eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal*. If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If a SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP is also an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts, whether or not deferred, to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included under Potential Payments upon Termination or Change-in-Control.

Pension Benefit Assumptions

The following assumptions were used in the present value calculations for all pension benefits:

- Discount rate — 4.20% Pension Plan and 3.75% supplemental plans as of December 31, 2014,
- Retirement date — Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement — RP-2014 mortality tables with generational projections,
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement — None,
- Form of payment for Pension Benefits:
    - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity
    - Female retirees: 75% single life annuity; 15% level income annuity; 5% joint and 50% survivor annuity; and 5% joint and 100% survivor annuity
- Spouse ages — Wives two years younger than their husbands,
- Annual performance-based compensation earned but unpaid as of the measurement date — 130% of target opportunity percentages times base rate of pay for year amount is earned, and
- Installment determination — 3.75 % discount rate for single sum calculation and 4.25% prime rate during installment payment period.

For all of the named executive officers, the number of years of credited service is one year less than the number of years of employment. The number of years of credited service for Ms. Greene reflects her previous employment with the Southern Company system.

Columns (d) and (e)

For Mr. McCrary, who retired effective May 1, 2014, column (d) reflects the actual benefits expected to be paid, and column (e) reflects the actual amount paid under the Pension Plan in 2014, as described above.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2014 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Employer Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
T. A. Fanning	239,141	47,539	337,542	—	3,360,041
A. P. Beattie	—	20,834	53,350	—	554,209
W. P. Bowers	149,632	26,669	650,324	—	4,510,207
K. S. Greene	—	19,890	4,795	—	35,944
S. E. Kuczynski	—	20,763	11,919	—	71,858
C. D. McCrary	—	1,393	113,931	1,709,936	3,967

The Company provides the DCP, which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred — the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.

The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Company stockholder. During 2014, the rate of return in the Stock Equivalent Account was 25.27%.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account, which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2014 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2014. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2014 were the amounts that were earned as of December 31, 2013 but were not payable until the first quarter of 2014. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2014 but not payable until early 2015. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer-matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years. The following chart shows the amounts previously reported.

	Amounts Deferred under the DCP prior to 2014 and previously reported ($)	Employer Contributions under the SBP prior to 2014 and previously reported ($)	Total ($)
T. A. Fanning	1,936,157	368,900	2,305,057
A. P. Beattie	34,781	61,314	96,095
W. P. Bowers	1,981,253	143,292	2,124,545
K. S. Greene	0	11,220	11,220
S. E. Kuczynski	0	19,905	19,905
C. D. McCrary	489,924	376,220	866,144

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE-IN-CONTROL

This section describes and estimates payments that could be made to the named executive officers serving as of December 31, 2014 under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2014 and assumes that the price of Common Stock is the closing market price on December 31, 2014.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible — Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation — Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off — Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination — Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of the Company's Drug and Alcohol Policy.
- Death or Disability — Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Company or the subsidiary company level:

- Company Change-in-Control I — Consummation of an acquisition by another entity of 20% or more of Common Stock or, following consummation of a merger with another entity, the Company's stockholders own 65% or less of the entity surviving the merger.
- Company Change-in-Control II — Consummation of an acquisition by another entity of 35% or more of Common Stock or, following consummation of a merger with another entity, the Company's stockholders own less than 50% of the Company surviving the merger.
- Company Termination — Consummation of a merger or other event and the Company is not the surviving company or Common Stock is no longer publicly traded.
- Subsidiary Company Change-in-Control — Consummation of an acquisition by another entity, other than another subsidiary of the Company, of 50% or more of the stock of any of the Company's subsidiaries, consummation of a merger with another entity and the Company's subsidiary is not the surviving company, or the sale of substantially all the assets of any of the Company's subsidiaries.

At the employee level:

Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason — Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

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

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if retire before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	Prorated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Restricted Stock Units	Forfeit.	Vest.	Forfeit.	Vest.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
DCP	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per the benefit administration committee's discretion.	Same as Retirement.
SBP – non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the DCP	Same as Retirement.

The following chart describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Company Change-in-Control I	Company Change-in-Control II	Company Termination or Subsidiary Company Change-in-Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension-related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Company Change-in-Control II.	Based on type of change-in-control event.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change-in-control, prorated at target performance level.	Same as Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
RSUs	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	Two or three times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2014.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2014 under the Pension Plan, the SBP-P, and the SERP are itemized in the following chart. The amounts shown under the Retirement column are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2014 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the Resignation or Involuntary Termination column are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2014 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefit amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Ms. Greene and Mr. Kuczynski were not retirement-eligible on December 31, 2014.

		Retirement ($)	Resignation or Involuntary Termination	Death (payments to a spouse) ($)
T. A. Fanning	Pension	8,207	treated as retiring	4,998
	SBP-P	1,239,797	treated as retiring	1,239,797
	SERP	506,098	treated as retiring	506,098
A. P. Beattie	Pension	10,689	treated as retiring	5,740
	SBP-P	568,034	treated as retiring	568,034
	SERP	219,450	treated as retiring	219,450
W. P. Bowers	Pension	8,737	treated as retiring	5,256
	SBP-P	640,352	treated as retiring	640,352
	SERP	210,117	treated as retiring	210,117
K. S. Greene	Pension	—	628	1,031
	SBP-P	—	192,311	22,072
	SERP	—	—	29,307
S. E. Kuczynski	Pension	—	—	406
	SBP-P	—	—	—
	SERP	—	—	—

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P and the SERP could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2014 following a change-in-control-related event, other than a Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

	SBP-P ($)	SERP ($)	Total ($)
T. A. Fanning	12,397,974	5,060,983	17,458,957
A. P. Beattie	5,680,337	2,194,503	7,874,840
W. P. Bowers	6,403,519	2,101,171	8,504,690
K. S. Greene	188,182	249,865	438,047
S. E. Kuczynski	—	—	—

The pension benefit amounts in the tables above were calculated as of December 31, 2014 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.79% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2014 is the greater of target or actual performance. Because actual payouts for 2014 performance were above the target level for all of the named executive officers, the amount that would have been payable was the actual amount paid as reported in the CD&A and the Summary Compensation Table.

Stock Options, Performance Shares, and Restricted Stock Units (Equity Awards)

Equity Awards would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all Equity Awards vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest. There is no payment associated with Equity Awards unless there is a Southern Company Termination and the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. For stock options, the value is the excess of the exercise price and the closing price of Common Stock on December 31, 2014. The value of performance shares and restricted stock units is calculated using the closing price of Common Stock on December 31, 2014. The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares and restricted stock units that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)			Total Number of Equity Awards Following Accelerated Vesting (#)			Total Payable in Cash without Conversion of Equity Awards ($)
	Stock Options	Performance Shares	Restricted Stock Units	Stock Options	Performance Shares	Restricted Stock Units	
T. A. Fanning	1,700,767	167,393	—	2,337,096	167,393	—	22,658,723
A. P. Beattie	453,576	44,425	—	755,968	44,425	—	7,582,510
W. P. Bowers	552,123	54,423	—	1,406,893	54,423	—	17,029,625
K. S. Greene	432,135	18,700	46,425	541,840	18,700	46,425	5,643,939
S. E. Kuczynski	343,802	33,846	30,931	805,398	33,846	30,931	9,081,360

DCP and SBP

The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table.

Healthcare Benefits

All of the named executive officers, except Ms. Greene and Mr. Kuczynski, are retirement-eligible. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing healthcare insurance premiums for up to a maximum of three years is $44,826 for Ms. Greene and $45,975 for Mr. Kuczynski.

Financial Planning Perquisite

An additional year of the financial planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement for retirement-eligible named executive officers.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events.

Severance Benefits

The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is three times the base salary and target payout under the annual Performance Pay Program for Mr. Fanning and two times the base salary and target payout under the annual Performance Pay Program for the other named executive officers. If any portion of the severance amount constitutes an "excess parachute payment" under Section 280G of the Code and is therefore subject to an excise tax, the severance amount will be reduced unless the after-tax "unreduced amount" exceeds the after-tax "reduced amount." Excise tax gross-ups will not be provided on change-in-control severance payments.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2014 in connection with a change in control.

	Severance Amount ($)
T. A. Fanning	7,920,000
A. P. Beattie	2,357,242
W. P. Bowers	2,755,683
K. S. Greene	2,210,000
S.E. Kuczynski	2,272,536

COMPENSATION RISK ASSESSMENT

The Company reviewed its compensation policies and practices and concluded that excessive risk-taking is not encouraged. This conclusion was based on an assessment of the mix of pay components and performance goals, the annual pay/performance analysis by the Compensation Committee's independent consultant, stock ownership requirements, compensation governance practices, and the claw-back provision. The assessment was reviewed with the Compensation Committee.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of independent Directors of the Company who have never served as executive officers of the Company. During 2014, none of the Company's executive officers served on the Board of Directors of any entities whose executive officers serve on the Compensation Committee.

EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2014 concerning shares of Common Stock authorized for issuance under Southern Company's existing non-qualified equity compensation plans.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights (a)	Weighted-average exercise price of outstanding options, warrants, and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	39,929,319	$40.55	15,179,865(1)
Equity compensation plans not approved by security holders	n/a	n/a	n/a

(1) Represents shares available for future issuance under the Omnibus Incentive Compensation Plan.

Item No. 5 — Ratification of Appointment of Independent Registered Public Accounting Firm

The Audit Committee of the Board of Directors is directly responsible for the appointment, retention, and oversight of the independent registered public accounting firm retained to audit the Company's financial statements, including the compensation of such firm and the related audit fee negotiations.

Deloitte & Touche has served as the Company's independent registered public accounting firm since 2002. To ensure continuing independence, the Audit Committee periodically considers whether there should be a change in the independent registered public accounting firm. The Audit Committee and its Chair also participate in the selection of Deloitte & Touche's lead engagement partner in connection with the mandatory rotation requirements of the SEC.

The Audit Committee has appointed Deloitte & Touche as the Company's independent registered public accounting firm for 2015. This appointment is being submitted to stockholders for ratification, and the Audit Committee and the Board of Directors believe that the continued retention of Deloitte & Touche to serve as the Company's independent registered public accounting firm is in the best interests of the Company and its stockholders.

Representatives of Deloitte & Touche will be present at the 2015 Annual Meeting to respond to appropriate questions from stockholders and will have the opportunity to make a statement if they desire to do so.

The affirmative vote of a majority of the votes cast is required for ratification of the appointment of the independent registered public accounting firm.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 5.

Audit Committee Report

The Audit Committee oversees the Company's financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for establishing and maintaining adequate internal controls over financial reporting, including disclosure controls and procedures, and for preparing the Company's consolidated financial statements. In fulfilling its oversight responsibilities, the Audit Committee reviewed the audited consolidated financial statements of the Company and its subsidiaries and management's report on the Company's internal control over financial reporting in the 2014 Annual Report to Stockholders attached hereto as Appendix D with management. The Audit Committee also reviews the Company's quarterly and annual reporting on Forms 10-Q and 10-K prior to filing with the SEC. The Audit Committee's review process includes discussions of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and estimates, and the clarity of disclosures in the financial statements.

The independent registered public accounting firm is responsible for expressing opinions on the conformity of the consolidated financial statements with accounting principles generally accepted in the United States and the effectiveness of the Company's internal control over financial reporting with the criteria established in "Internal Control — Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Audit Committee has discussed with the independent registered public accounting firm the matters that are required to be discussed by the Public Company Accounting Oversight Board (PCAOB) Auditing Standard No. 16, *Communications with Audit Committees* and SEC Rule 2-07 of Regulation S-X, *Communications with Audit Committees*. In addition, the Audit Committee has discussed with the independent registered public accounting firm its independence from management and the Company as required under rules of the PCAOB and has received the written disclosures and letter from the independent registered public accounting firm required by the rules of the PCAOB. The Audit Committee also has considered whether the independent registered public accounting firm's provision of non-audit services to the Company is compatible with maintaining the firm's independence.

The Audit Committee discussed the overall scope and plans with the Company's internal auditors and independent registered public accounting firm for their respective audits. The Audit Committee meets with the internal auditors and the independent registered public accounting firm, with and without management present, to discuss the results of their audits, evaluations by management and the independent registered public accounting firm of the Company's internal control over financial reporting, and the overall quality of the Company's financial reporting. The Audit Committee also meets privately with the Company's compliance officer. The Audit Committee held ten meetings during 2014.

In reliance on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors (and the Board approved) that the audited consolidated financial statements be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and filed with the SEC. The Audit Committee also reappointed Deloitte & Touche as the Company's independent registered public accounting firm for 2015. Stockholders will be asked to ratify that selection at the 2015 Annual Meeting.

Members of the Audit Committee as of December 31, 2014:

Jon A. Boscia, Chair
Juanita Powell Baranco
Warren A. Hood, Jr.
Larry D. Thompson

Principal Independent Registered Public Accounting Firm Fees

The following represents the fees billed to the Company for the two most recent fiscal years by Deloitte & Touche — the Company's principal independent registered public accounting firm for 2014 and 2013.

	2014	2013
	(in thousands)	
Audit Fees (1)	$11,794	$11,704
Audit-Related Fees (2)	126	110
Tax Fees	—	50
All Other Fees (3)	191	29
Total	$12,111	$11,893

(1) Includes services performed in connection with financing transactions.

(2) Includes non-statutory audit services in both 2014 and 2013.

(3) Represents registration fees for attendance at Deloitte & Touche-sponsored education seminars in 2013 and 2014, subscription fees for Deloitte & Touche's technical accounting research tool in 2013 and 2014, information technology consulting services related to general ledger software of the Company in 2014, and travel expenses for Deloitte & Touche's training facilitator in 2013.

The Audit Committee has adopted a Policy on Engagement of the Independent Auditor for Audit and Non-Audit Services (see Appendix C) that includes requirements for the Audit Committee to pre-approve services provided by Deloitte & Touche. This policy was initially adopted in July 2002 and, since that time, all services included in the chart above have been pre-approved by the Audit Committee.

ITEM NO. 6 — STOCKHOLDER PROPOSAL ON PROXY ACCESS

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 6

The Company has been advised that a stockholder proposes to submit the following resolution at the 2015 Annual Meeting. The name, address, and beneficial ownership of such stockholder are available upon request.

"RESOLVED: Shareholders of The Southern Company (the "Company") ask the board of directors (the "Board") to adopt, and present for shareholder approval, a "proxy access" bylaw. Such a bylaw shall require the Company to include in proxy materials prepared for a shareholder meeting at which directors are to be elected the name, Disclosure and Statement (as defined herein) of any person nominated for election to the board by a shareholder or group (the "Nominator") that meets the criteria established below. The Company shall allow shareholders to vote on such nominee on the Company's proxy card.

"The number of shareholder-nominated candidates appearing in proxy materials shall not exceed one quarter of the directors then serving. This bylaw, which shall supplement existing rights under Company bylaws, should provide that a Nominator must:

a) have beneficially owned 3% or more of the Company's outstanding common stock continuously for at least three years before submitting the nomination;

b) give the Company, within the time period identified in its bylaws, written notice of the information required by the bylaws and any Securities and Exchange Commission rules about (i) the nominee, including consent to being named in the proxy materials and to serving as director if elected; and (ii) the Nominator, including proof it owns the required shares (the "Disclosure"); and

c) certify that (i) it will assume liability stemming from any legal or regulatory violation arising out of the Nominator's communications with the Company shareholders, including the Disclosure and Statement; (ii) it will comply with all applicable laws and regulations if it uses soliciting material other than the Company's proxy materials; and (c) to the best of its knowledge, the required shares were acquired in the ordinary course of business and not to change or influence control at the Company.

"The Nominator may submit with the Disclosure a statement not exceeding 500 words in support of the nominee (the "Statement"). The Board shall adopt procedures for promptly resolving disputes over whether notice of a nomination was timely, whether the Disclosure and Statement satisfy the bylaw and applicable federal regulations, and the priority to be given to multiple nominations exceeding the one-quarter limit.

SUPPORTING STATEMENT

"We believe proxy access is a fundamental shareholder right that will make directors more accountable and contribute to increased shareholder value. The CFA Institute's 2014 assessment of pertinent academic studies and the use of proxy access in other markets similarly concluded that proxy access:

- Would "benefit both the markets and corporate boardrooms, with little cost or disruption."

- Has the potential to raise overall US market capitalization by up to $140.3 billion if adopted market-wide. (http://www.cfapubs.org/doi/pdf/10.2469/ccb.v2014.n9.1)

"The proposed bylaw terms enjoy strong investor support — votes for similar shareholder proposals averaged 55% from 2012 through September 2014 — and similar bylaws have been adopted by companies of various sizes across industries, including Chesapeake Energy, Hewlett-Packard, Western Union and Verizon.

"We urge shareholders to vote FOR this proposal."

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 6 FOR THE FOLLOWING REASONS:

Proxy access, which refers to the ability of stockholders holding a small percentage of the Company's shares to require the Company to undertake the effort and expense of including their Director nominees in the Company's proxy materials and thus trigger a proxy contest, is an untested governance feature for U.S. companies. The Board of Directors continually evaluates the Company's governance profile and believes that proxy access should not be implemented in the absence of a compelling rationale. The proponent's proxy access proposal does not seek to remedy any specific governance or performance deficiency at the Company; in fact, it appears the Company was targeted with this proposal solely because its business involves the consumption of fossil fuels and not because of any development related to proxy access.

The Company's stockholders already have significant and meaningful corporate governance rights. This includes the ability to recommend Director candidates for independent consideration by the Governance Committee and the ability to register disapproval of individual Directors or the full Board, on an annual basis, by means of the Company's majority voting standard and Director resignation policy. In addition, stockholders holding as few as 10% of the outstanding shares of Common Stock have the right to request a special meeting of stockholders.

Southern Company has consistently created value for its stockholders and there is no need for proxy access.

- The most recent dividend, paid March 6, 2015, marks the 269th consecutive quarter the Company has paid a dividend equal to or higher than the previous quarter.
- The Southern Company generation system's Equivalent Forced Outage Rate is at industry-leading levels (1.9% compared to five-year national average of approximately 9.0%).
- The Company and its four traditional operating company subsidiaries occupied the top five spots for customer satisfaction for all customer classes combined in the customer value benchmark survey, an annual peer comparison of U.S. electric utilities.
- With respect to compensation matters, the Company has received stockholder support in its annual say-on-pay vote of in excess of 94% of votes cast since the vote was first held in 2011.

Southern Company stockholders already have access to robust and effective procedures to communicate with and influence the Board of Directors and hold it accountable.

- The full Board of Directors is elected annually and the Company has a majority voting standard in uncontested Director elections, combined with a resignation policy for candidates who fail to receive a majority of votes cast (see page 13).
- Management proactively engages with stockholders on corporate governance issues (see page 12).
- The Company holds an annual say-on-pay vote on executive compensation (see page 24).

- The Board of Directors has established a mechanism for stockholders to directly communicate with the Board or with specified Directors (see page 12).
- The Company regularly engages with stockholders and other concerned parties on environmental issues and has provided significant voluntary disclosure.

Southern Company already has significant corporate governance practices that protect stockholder rights and interests.

- The Company has a threshold of just 10% of outstanding shares for stockholders to request a special meeting.
- Stockholders must approve amendments to the Company's certificate of incorporation and By-Laws, so the Board of Directors cannot unilaterally take away any rights granted to stockholders in the Company's governing documents.
- The Company has not adopted a "poison pill" stockholder rights plan and the Board of Directors does not have the authority to issue "blank check" preferred stock.
- If Proposal No. 3 is approved by stockholders, the Company's certificate of incorporation and By-Laws will not restrict stockholders' ability to act by written consent to the fullest extent allowed by applicable Delaware law (see page 9).

The Board of Directors is already highly-qualified, diverse, and independent.

All members of the Board of Directors, other than the Chief Executive Officer, are independent of management and the Board has a strong Lead Independent Director to provide a source of independent leadership (see page 15). The Board periodically refreshes its membership to ensure it adds helpful experience and fresh perspectives and maintains appropriate diversity. Since the beginning of 2014, the Board of Directors has added three new members – Ms. Hudson and Messrs. Thompson and Johns, which means the Board now includes three female members and three ethnic minorities. The Board's commitment to refreshment is reflected in its overall average Board tenure, which is less than six years.

Implementing proxy access could negatively affect the Company's corporate governance.

Bypassing the independent Governance Committee process for nominations.

Implementing proxy access would provide a small percentage of stockholders, who do not have a fiduciary obligation to other stockholders and who may have a narrow agenda, the right to include Director nominees in the Company's proxy statement, bypassing the Company's independent nomination process. Currently, absent a proxy contest, all nominees are recommended to the full Board of Directors for nomination by the Governance Committee. Stockholders may participate in this process by submitting recommendations of candidates for consideration by the Governance Committee (see page 19). The Governance Committee is composed entirely of independent Directors, and the Board and the Governance Committee each have a fiduciary duty to make nominations that are in the best interests of all stockholders. The Board of Directors and the Governance Committee are in the best position to evaluate Director candidates, in light of the need for a full Board that is composed of a group of Directors with complementary skills, experience, and perspectives and that meets the unique needs of the Company.

Increasing the influence of special interests and fragmenting the Board of Directors.

If proxy access were implemented, a small minority of stockholders could nominate Director candidates to further a special interest agenda that may not be in the best interest of the Company as a whole. Opposing such candidates in a contested election would be time-consuming and costly for the

Company. Accordingly, even if special interest Directors were not elected, such stockholders could still attempt to use proxy access to extract concessions from the Company related to their special interests. Moreover, the election of Directors nominated by a small percentage of stockholders with special interests could also result in the creation of factions on the Board of Directors, making it more difficult for the Board to reach consensus on behalf of all stockholders, thereby delaying important decision-making.

Proxy access could lead to continually contested elections, which would impose costs on the Company, divert management's and the Board's attention, and potentially discourage highly-qualified Directors from serving.

Providing proxy access for a group of stockholders owning just 3% of the Company's outstanding shares could make contested elections much more commonplace. Currently, stockholders seeking to nominate Director candidates must, like the Company, bear their own costs of soliciting votes for their proposed nominees. This existing system helps ensure that a stockholder is serious about its intention to nominate Directors, because the stockholder must bear the cost of its own solicitation. Proxy access would shift this cost to the Company, at no risk to the stockholder. In addition, the prospect of having to stand in a contested election routinely could cause highly-qualified Directors to be reluctant to serve on the Board of Directors.

The vote needed to pass the proponent's resolution is the affirmative vote of a majority of the votes cast.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 6.

Item no. 7 — Greenhouse Gas Emissions Reduction Goals 2015

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 7.

The Company has been advised that a stockholder, together with multiple co-filers, proposes to submit the following resolution at the 2015 Annual Meeting. The names, addresses, and beneficial ownership of such stockholder and co-filers are available upon request.

RESOLVED:
"Shareholders request that Southern Company adopt absolute, quantitative time-bound goals for reducing total greenhouse gas (GHG) emissions from operations and report to shareholders by November 1, 2015 on its plans to achieve these goals (omitting proprietary information and prepared at reasonable cost.)"

WHEREAS:
"The 2014 *Synthesis Report* of the Intergovernmental Panel on Climate Change (IPCC) warns that continued greenhouse gas (GHG) emissions and subsequent global warming will have "severe, pervasive and irreversible impacts for people and ecosystems." The *Risky Business* report forecasts significant economic costs to agriculture, labor productivity, and property.

"To mitigate the worst impacts of climate change and limit warming to below 2°C, as agreed in the Copenhagen Accord, the IPCC estimates that a fifty percent reduction in GHG emissions globally is needed by 2050, relative to 1990 levels.

"Our country's fleet of fossil fueled power plants is the single largest source of carbon pollution in the U.S., accounting for over one-third of total carbon emissions, according to the Environmental Protection Agency (EPA.) Plans for increased regulation of GHG emissions are already underway, posing regulatory risk to the company. President Obama committed to reduce emissions by 26-28 percent by 2025. The EPA's Clean Power Plan would strengthen emissions standards for power plants, seeking an overall 30 percent reduction of CO2 emissions by 2030. With the fourth highest power generation from burning coal in the country and the third highest level of carbon emissions of U.S. power producers, compliance with this rule will likely require substantial adjustments to Southern facilities, entailing emissions reductions, increased use of renewable energy and deployment of energy efficiency. Meanwhile, Southern has publicly stated that it does not support this regulation.

"Southern Company has made significant investments in renewable energy, efficiencies, and a more diversified energy mix. Setting clear proactive goals to manage greenhouse gas emissions at Southern Company and its operating companies would enable the Company to manage climate risk and align with a growing global commitment to contain emissions. Sixty percent of Fortune 100 companies have set GHG reduction goals or renewable energy targets. Southern lags behind peers including American Electric Power, CMS Energy, Exelon and Duke Energy which have set absolute and/or intensity carbon reduction goals. NRG Energy announced its aim to reduce its carbon emissions 50 percent by 2030 and 90 percent by 2050.

SUPPORTING STATEMENT:
"A disciplined business strategy to cut emissions includes setting goals, striving to meet them and reporting on progress. Leading practices for electric utilities to manage carbon across the enterprise include pursuing all cost-effective energy efficiency opportunities, deploying large-scale and distributed renewable energy, utilizing smart grid technologies for consumer and system benefit, and serving as a systems integrator providing services to meet varying customer needs; and conducting robust and transparent resource planning. Two commonly used options for setting GHG targets are GHG "intensity" or "absolute" targets. Absolute GHG reduction goals compare total GHG emissions in the goal year to those in a base year."

X THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 7 FOR THE FOLLOWING REASONS:

The Board of Directors does not believe it is in the best interests of the Company or its stockholders at this time to establish voluntary, absolute quantitative goals for reducing total greenhouse gas (GHG) emissions from the Southern Company system's operations. Independently establishing these types of goals would not add value to the Company's already robust research, development, and deployment efforts relating to new technology to reduce GHG emissions, would be premature given the Environmental Protection Agency's (EPA) proposed regulations relating to GHG emissions from new and existing sources, and would not be an efficient use of additional Company resources given the ongoing reporting and significant policy engagement by the Company in this area.

The Southern Company system is committed to a diverse energy mix. With a strong base of natural gas, coal, nuclear, hydro, and growing renewable generating capacity, the Southern Company system's fleet is flexible, allowing it to choose the most cost effective fuel source to best serve customers with clean, safe, reliable, and affordable energy. The Southern Company system is dedicated to a full portfolio of resources for the United States' energy future — twenty-first century coal, natural gas, renewables, new nuclear, and energy efficiency.

Currently, the EPA is in the process of promulgating carbon dioxide regulations that will affect new, existing, and modified and reconstructed power plants. Final emission standards for new sources and for modified and reconstructed sources and final emission reduction guidelines for existing sources are expected this year from the EPA. Independently establishing reduction goals without the benefit of these final rules is premature. Even absent regulations, the Southern Company system's GHG emissions in 2014 were almost 20% lower than 2005 levels.

The Southern Company system is a leader in the industry in developing technologies to reduce GHG emissions in the generation of electric energy and has committed substantial financial and human resources to research, develop, and deploy such technologies. This leadership is best evidenced by the Southern Company system's efforts to develop carbon capture and storage. The Southern Company system was selected by the U.S. Department of Energy (DOE) to manage and operate the DOE's National Carbon Capture Center in Alabama, a focal point of national efforts to reduce GHG emissions from coal-based power plants through technological innovation. Additionally, the Company has joined the DOE and other partners to demonstrate carbon capture and storage at a coal-based power plant in Alabama. The Company and its partners have developed an advanced coal gasification technology known as Transport Integrated Gasification (TRIG™) designed to produce less carbon dioxide emissions than the current fleet of existing coal plants. The Company's subsidiary, Mississippi Power, is constructing the Kemper IGCC using TRIG™ technology, which is designed to include the capture and sequestration (via enhanced oil recovery) of at least 65 percent of the carbon dioxide produced by the Kemper IGCC during operations.

Additionally, as nuclear power re-emerges as a viable way to meet new demand for electricity, with the added benefit of no emissions of GHG, Southern Company, through its subsidiary Georgia Power, is leading the nation's nuclear energy renaissance with the construction of two new nuclear units at Plant Vogtle.

The Company has created a number of reports disclosing its actions related to GHG and other emissions. In 2006, the Company's long-standing Environmental Progress Reports evolved into its *Corporate Responsibility Report*, which includes data on emissions and actions being undertaken to address those emissions. Additionally, the Company has also published for a number of years its climate and carbon disclosure reports, which describe specific current and long-term activities to address GHG emissions. The reports are updated on an annual basis. These reports are available either through the Company's external website at http://www.southerncompany.com/what-doing/corporate-responsibility/home.cshtml or by contacting Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308 and requesting a copy.

For a number of years, the Company also has actively engaged its stakeholders regarding environmental matters affecting the Southern Company system. Since 2011, the Company has held environmental stakeholder forums, webinars, calls, and meetings covering a range of topics from regulatory and policy issues and system risk and planning to renewables, energy efficiency, and GHG issues.

In summary, the Board of Directors does not believe it is in the best interests of the Company or its stockholders to independently establish at this time voluntary, absolute quantitative goals for reducing total GHG emissions from the Southern Company system's operations due to (1) the Southern Company system's already robust research, development, and deployment efforts relating to new technology to reduce GHG emissions, (2) the EPA's pending regulations governing GHG emissions from new and existing sources, which are not yet finalized, and (3) the Company's ongoing practice of reporting emissions data, emission reduction results, investment, and significant policy engagement. A separate report as requested in the proposal regarding plans to achieve such goals would not be an efficient use of additional Company resources or add value to the Company's current efforts in this area.

The vote needed to pass the proponents' resolution is the affirmative vote of a majority of the votes cast.

X THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 7.

Frequently Asked Questions

Q: When will the Proxy Statement be mailed?

A: The Proxy Statement will be mailed on or about April 10, 2015.

Q: Who is entitled to vote?

A: All stockholders of record at the close of business on the record date of March 30, 2015 may vote.

Q: How do I give voting instructions?

A: You may attend the meeting and give instructions in person or give instructions by internet, by phone, or by mail. Information for giving instructions is on the form of proxy and trustee voting instruction form (proxy form). For those investors whose shares are held by a broker, bank, or other nominee, you must complete and return the voting instruction form provided by your broker, bank, or nominee in order to instruct your broker, bank, or nominee on how to vote. The Proxies, named on the enclosed proxy form, will vote all properly executed proxies that are delivered pursuant to this solicitation and not subsequently revoked in accordance with the instructions given by you.

Q: Why is my vote important?

A: It is the right of every investor to vote on certain matters that affect the Company.

Q: Can I change my vote?

A: Yes. If you are a holder of record, you may revoke your proxy by submitting a subsequent proxy, or by written request received by the Company's Corporate Secretary prior to the meeting, or by attending the meeting and voting your shares. If your shares are held through a broker, bank, or other nominee, you must follow the instructions of your broker, bank, or other nominee to revoke your voting instructions.

Q: How are votes counted?

A: Each share counts as one vote. A quorum is required to transact business at the 2015 Annual Meeting. Stockholders of record holding shares of stock constituting a majority of the shares entitled to be cast shall constitute a quorum. Abstentions that are marked on the proxy form and broker non-votes are included for the purpose of determining a quorum, but shares that otherwise are not voted are not counted toward a quorum. Neither abstentions, broker non-votes, nor shares that otherwise are not voted are counted for or against each of the matters being considered at the 2015 Annual Meeting and thus will not affect the outcome of the vote for these items, except that abstentions will have the same effect as votes "against" Item No. 3.

Q: What are broker non-votes?

A: Broker non-votes occur on a matter up for vote when a broker, bank, or other holder of shares you own in "street name" is not permitted to vote on that particular matter without instructions from you, you do not give such instructions, and the broker, bank, or other nominee indicates on its proxy form, or otherwise notifies the Company, that it does not have authority to vote its shares on that matter. Whether a broker has authority to vote its shares on uninstructed matters is determined by NYSE rules.

Q: What does it mean if I get more than one proxy form?

A: You will receive a proxy form for each account that you have. Please vote proxies for all accounts to ensure that all of your shares are voted. If you wish to consolidate multiple registered accounts, please contact Shareowner Services at Computershare Inc. at (800) 554-7626.

Q: Can the Proxy Statement be accessed from the internet?

A: Yes. You can access the Company's website at **http://investor.southerncompany.com/proxy** to view the Proxy Statement.

Q: How do I attend the 2015 Annual Meeting in person?

A: All attendees need to bring photo identification, such as a driver's license, to gain admission to the 2015 Annual Meeting. If you are a holder of record, the top half of your proxy card is your admission ticket. If you hold your shares in street name, you will need proof of ownership to be admitted to the meeting. Examples of proof of ownership are a recent brokerage statement or a letter from your bank or broker. If you want to vote your shares held in street name, you must get a legal proxy in your name from the broker, bank, or other nominee that holds your shares. Please note that cameras, sound or video recording equipment, cellular telephones, smartphones or other similar equipment, and electronic devices are not permitted to be used during the 2015 Annual Meeting.

Q: Does the Company offer electronic delivery of proxy materials?

A: Yes. Most stockholders can elect to receive an email that will provide an electronic link to the Proxy Statement, which includes the 2014 Annual Report as an appendix. Opting to receive your proxy materials on-line will save the Company the cost of producing and mailing documents and also will give you an electronic link to the proxy voting site.

You may sign up for electronic delivery when you vote your proxy via the internet or by visiting www.icsdelivery.com/so. Once you enroll for electronic delivery, you will receive proxy materials electronically as long as your account remains active or until you cancel your enrollment. If you consent to electronic access, you will be responsible for your usual internet-related charges (e.g., on-line fees and telephone charges) in connection with electronic viewing and printing of the Proxy Statement, which includes the 2014 Annual Report as an appendix. The Company will continue to distribute printed materials to stockholders who do not consent to access these materials electronically.

Q: What is "householding?"

A: Stockholders sharing a single address may receive only one copy of the Proxy Statement, which includes the 2014 Annual Report as an appendix, unless the transfer agent, broker, bank, or other nominee has received contrary instructions from any owner at that address. This practice — known as householding — is designed to reduce printing and mailing costs. If a stockholder of record would like to either participate or cancel participation in householding, he or she may contact Shareowner Services at Computershare Inc. at (800) 554-7626 or by mail at The Southern Company, c/o Computershare, P.O. Box 30170, College Station, TX 77842-3170. If you own indirectly through a broker, bank, or other nominee, please contact your financial institution.

Q: What is the Board's recommendation for the proposals?

A: The Board of Directors recommends votes "FOR" each of Item Nos. 1, 2, 3, 4, and 5 and votes "AGAINST" Item Nos. 6 and 7 in this Proxy Statement.

Q: How many votes are needed to approve each of the items of business?

A: The affirmative vote of a majority of the votes cast is required for approval of each of Item Nos. 1, 2, 4, 5, 6, and 7. For Item No. 3, the affirmative vote of a majority of the shares represented in person or by proxy and entitled to vote at the 2015 Annual Meeting is required for approval.

Q: When are stockholder proposals due for the 2016 Annual Meeting of Stockholders?

A: The deadline for the receipt of stockholder proposals to be considered for inclusion in the Company's proxy materials for the 2016

Annual Meeting of Stockholders is December 12, 2015. Proposals must be submitted in writing to Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Additionally, the proxy solicited by the Board of Directors for next year's meeting will confer discretionary authority to vote on any stockholder proposal presented at that meeting that is not included in the Company's proxy materials unless the Company is provided written notice of such proposal no later than February 25, 2016.

Q: Who is soliciting these proxies and who pays the expense of such solicitations?

A: These proxies are being solicited on behalf of the Company's Board of Directors. The Company pays the cost of soliciting proxies. The Company has retained Georgeson Inc. to assist with the solicitation of proxies for a fee of $12,500, plus additional fees for telephone and other solicitation of proxies or other services, if needed, and reimbursement of out-of-pocket expenses. The officers or other employees of the Company or its subsidiaries may solicit proxies to have a larger representation at the meeting. None of these officers or other employees of the Company will receive any additional compensation for these services. Upon request, the Company will reimburse brokerage houses and other custodians, nominees, and fiduciaries for their reasonable out-of-pocket expenses for forwarding solicitation material to the beneficial owners of the Company's common stock.

Section 16(a) Beneficial Ownership Reporting Compliance

Based on the Company's review of Forms 3, 4, and 5 and amendments thereto in the Company's possession and written representations furnished to the Company, the Company believes that no reporting person of the Company failed to file, on a timely basis, the reports required by Section 16(a) of the Securities Exchange Act of 1934, as amended, except for an inadvertent late filing of a Form 4 to disclose one transaction by David J. Grain.

Certain Relationships and Related Transactions

Mr. Donald M. James, a Director of the Company, served as the Chief Executive Officer of Vulcan Materials Company from 1997 to 2014. During 2014, subsidiaries of the Company purchased approximately $2.1 million of goods and services from Vulcan Materials Company and its affiliates, primarily related to on-going construction projects.

Mr. E. Jenner Wood III, a Director of the Company, is Chairman, President, and Chief Executive Officer of the Atlanta Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc. During 2014, subsidiaries of the Company made payments of approximately $1.1 million to certain subsidiaries of SunTrust Banks, Inc., substantially related to aircraft leases.

During 2014, certain subsidiaries of SunTrust Banks, Inc. also furnished a number of regular banking services in the ordinary course of business to the Company and its subsidiaries and served as an underwriter for certain securities offerings of the Company and its subsidiaries for which $1.7 million was received by these certain subsidiaries of SunTrust Banks, Inc. The Company and its subsidiaries intend to maintain normal banking relations with SunTrust Banks, Inc. and its subsidiaries in the future.

The Company does not have a written policy pertaining solely to the approval or ratification of "related party transactions." The Company has a Code of Ethics as well as a Contract Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/ services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

OUTSIDE DIRECTORS STOCK PLAN FOR THE SOUTHERN COMPANY AND ITS SUBSIDIARIES

Outside Directors Stock Plan for The Southern Company and its Subsidiaries

Article I—Purpose and Adoption of Plan

1.1 Adoption. The Southern Company hereby adopts the Outside Directors Stock Plan for The Southern Company and Its Subsidiaries, effective June 1, 2015 subject to (a) the approval of the Plan by the stockholders of the Company at the annual meeting thereof to be held on May 27, 2015 and (b) registration of the Stock to be issued pursuant to the Plan.

1.2 Purpose. The Plan is designed to more closely align the interests of Directors with the interests of the stockholders of the Company through ownership of Stock.

Article II—Definitions

2.1 "Affiliated Employer" shall mean any corporation which is a member of the controlled group of corporations of which the Company is the common parent corporation.

2.2 "Board of Directors" shall mean either the Southern Board or a System Company Board, as applicable to a Director.

2.3 "Commission" shall mean the Securities and Exchange Commission.

2.4 "Company" shall mean The Southern Company.

2.5 "Company Board" shall mean the Board of Directors of The Southern Company.

2.6 "Director" shall mean any person who is not an active employee of the Company or a System Company and who either serves on the Company Board or a System Company Board.

2.7 "Effective Date" shall mean June 1, 2015.

2.8 "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

2.9 "Market Value" shall mean the following:

(a) With respect to Stock that is issued by the Company, the closing price of the Stock, as published in the Wall Street Journal in its report of New York Stock Exchange composite transactions, on the date such Market Value is to be determined, as specified herein.

(b) With respect to Stock that is purchased on the open market, the actual purchase price paid for the Stock on the date purchased.

2.10 "Participant" shall mean each Director who meets the requirements of Section 3.1 of the Plan.

2.11 "Plan" shall mean the Outside Directors Stock Plan for The Southern Company and Its Subsidiaries, as amended from time to time.

2.12 "Plan Administrator" shall mean the Governance Committee of the Company Board.

2.13 "Plan Year" shall mean the calendar year.

2.14 "Retainer Fee" shall mean the annual rate of the fees paid to a Director as determined by the Board of Directors from time-to-time, but excluding reimbursements for expenses and any additional fees or compensation for (a) attendance at the meetings of the Board of Directors or any committee, (b) service on a committee and (c) service at the request of the Board of Directors or a committee.

2.15 "Stock" shall mean the Company's common stock, par value $5.00 per share.

2.16 "System Company" shall mean any Affiliated Employer which adopted the Outside Directors Stock Plan for Directors of The Southern Company and its Subsidiaries that was effective May 26, 2004 and any additional Affiliated Employer the Company Board may from time to time determine to bring under the Plan and which shall adopt the Plan. The System Companies that have adopted the Plan are listed in Schedule A, attached hereto, as such Schedule may be amended from time to time.

2.17 "System Company Board" shall mean the Board of Directors of a System Company.

The masculine pronoun shall be construed to include the feminine pronoun and the singular shall include the plural, where the context so requires.

Article III—Eligibility

3.1 Eligibility Requirements.

(a) Except as provided in Subsection (b), each Director shall become a Participant in the Plan on the first date such Director serves on the Board of Directors.

(b) For purposes of the 2015 Plan Year, a Director who is serving on a Board of Directors as of the Effective Date shall become a Participant in the Plan on the Effective Date.

Article IV—Form and Time of Benefit Distributions

4.1 Stock Grant. Each Participant shall receive a portion of his Retainer Fee in Stock. Any remainder of such Retainer Fee and any meeting attendance fees, in increments elected by the Director in accordance with Section 4.2, may be paid in cash or in Stock. The portion of the Retainer Fee required to be paid in Stock pursuant to this Section 4.1 may be denominated in dollars or a fixed number of shares of Stock and shall be stated in Schedule B, attached hereto, as such Schedule shall be amended from time to time by the Board of Directors.

4.2 Election to Determine Percentage or Amount of Compensation to be Paid in Stock. Prior to the beginning of each Plan Year, each Participant shall have an opportunity to elect to have the non-Stock portion of his Retainer Fee paid in cash or Stock of the Company, or a combination thereof. Each Participant also shall have an opportunity to elect to have a portion of any meeting attendance fees paid in Stock. Nothing contained in this Section 4.2 shall be interpreted in such a manner as would disqualify the Plan from treatment as a "formula plan" under Rule 16b-3, as promulgated by the Commission under the Exchange Act, as that rule may be amended from time to time.

4.3 Amount of Stock Compensation Denominated in Dollars. For Stock compensation that is denominated in dollars, the number of shares of Stock due to a Participant, including any fractional shares, shall be determined by dividing the prescribed dollar amount by the Market Value on the compensation payment date.

4.4 Deferral of Stock Compensation. Any portion of the Retainer Fee that is required to be paid in Stock pursuant to Section 4.1 may be deferred in accordance with the terms of the Deferred Compensation Plan maintained by the Company or System Company for its Directors. Any other Director compensation that a participant may elect to receive in Stock under the Plan may be similarly deferred.

4.5 Death Benefits. No grants of Stock shall be made to any beneficiary of a Participant following a Participant's death.

Article V—Administration of Plan

5.1 Administrator. The general administration of the Plan shall be the responsibility of the Plan Administrator.

5.2 Powers. The Plan Administrator shall administer the Plan

(a) The Plan Administrator shall administer the Plan in accordance with its terms and shall have all powers necessary to carry out the provisions of the Plan. It shall interpret the Plan and shall have the discretion to determine all questions arising in the administration, interpretation and application of the Plan, including any ambiguities contained herein or any questions of fact. Any such determination by it shall be conclusive and binding on all persons. It may adopt such procedures as it deems desirable for the conduct of its affairs. It may appoint such accountants, counsel, actuaries, specialists and other persons as it deems necessary or desirable in connection with the administration of the Plan, and shall be the agent for the service of process.

(b) The Plan Administrator may delegate to such officers, employees or departments of the Company or an affiliate of the Company, such authority, duties and responsibilities of the Plan Administrator as it, in its sole discretion, considers necessary or appropriate for the proper and efficient operation of the Plan, including, without limitation, interpretation of the Plan and establishment of procedures for administration of the Plan.

5.3 Indemnification. The System Companies and the Company shall indemnify the Plan Administrator against any and all claims, losses, damages, expenses and liability arising from any action or failure to act, except when the same is finally judicially determined to be due to gross negligence or willful misconduct. The System Companies and the Company may purchase at their own expense sufficient liability insurance for the Plan Administrator to cover any and all claims, losses, damages and expenses arising from any action or failure to act in connection with the execution of the duties as Plan Administrator.

Article VI—Miscellaneous

6.1 Assignment. Neither the Participant nor his legal representative shall have any rights to sell, assign, transfer or otherwise convey the right to receive the payment of any benefit due hereunder, which payment and the right thereto are expressly declared to be nonassignable and nontransferable. Any attempt to assign or transfer the right to payment under the Plan shall be null and void and of no effect.

6.2 Amendment and Termination. The Plan may be wholly or partially amended or otherwise modified, suspended or terminated at any time by the Company Board or by its Governance Committee with the approval of the Company Board, upon execution of a duly authorized written document; provided, however, that, without the approval of the stockholders of the Company entitled to vote thereon, no amendment may be made which would, absent such stockholder approval, disqualify the Plan for coverage under Rule 16b-3, as promulgated by the Commission under the Exchange Act, as that rule may be amended from time to time. Notwithstanding the foregoing, no such amendment or termination shall impair any rights to payments to which a Participant may be entitled prior to the effective date of such amendment or termination.

6.3 No Guarantee of Continued or Future Service on a Board of Directors. Participation hereunder shall not be construed as creating a right in any Director to continued service or future service on the Board of Directors. Participation hereunder does not constitute an employment contract between any Director and any System Company or the Company as the case may be.

6.4 Construction. This Plan shall be construed in accordance with and governed by the laws of the State of Georgia, to the extent such laws are not otherwise superseded by the laws of the United States.

IN WITNESS WHEREOF, the Company Board, through its duly authorized officers, has adopted this Outside Directors Stock Plan for The Southern Company and Its Subsidiaries this 9th day of February, 2015, to be effective as provided herein.

THE SOUTHERN COMPANY:

By:____________________________________
Its: Secretary

Attest:

By:____________________________________
Its: Assistant Secretary

Schedule A

The System Companies as of May 27, 2015 are:

Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company

Schedule B

As of June 1, 2015

The portion of a Participant's Retainer Fee required to be distributed in Stock shall be determined in accordance with the following schedule:

Company	Dollar Amount of Required Stock Distribution
Southern Company	$105,000
Alabama Power Company	$30,000
Georgia Power Company	$30,000
Gulf Power Company	$19,500
Mississippi Power Company	$19,500

Proposed Amendment to Section 46 of the Company's By-laws

The text of the proposed amendment to Section 46 of the Company's By-Laws, marked to show changes to the current Section 46, is set forth as follows:

46. The By-Laws of the Corporation may be altered, amended or repealed (a) at any meeting of the Board of Directors by the vote of a majority of the entire Board then in office, or (b) by the vote of the holders of a majority of that part of the capital stock of the Corporation having voting powers which is represented in person or by proxy at any annual meeting of stockholders or at any special meeting called for that purpose (provided that a lawful quorum of stockholders be there represented in person or by proxy), or (c) without a meeting by the written consent of the holders of ~~all of~~ not less than the minimum number of the issued and outstanding shares of capital stock of the Corporation having voting powers that would be necessary to take such action at a meeting at which all shares entitled to vote thereon were present and voted; provided, however, that the Board of Directors shall not have power to alter, amend or repeal the provisions of Sections 5, 44 or 46 of the By-Laws and provided, further, that an alteration, amendment or repeal of any other provision of the By-Laws by the Board of Directors shall cease to be effective unless submitted to and ratified or approved at the next annual or special meeting at which a lawful quorum of stockholders is represented in person or by proxy by the vote of the holders of a majority of that part of the capital stock of the Corporation having voting powers which is represented in person or by proxy at such meeting.

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Policy on Engagement of the Independent Auditor for Audit and Non-Audit Services

A. Southern Company (including its subsidiaries) will not engage the independent auditor to perform any services that are prohibited by the Sarbanes-Oxley Act of 2002. It shall further be the policy of the Company not to retain the independent auditor for non-audit services unless there is a compelling reason to do so and such retention is otherwise pre-approved consistent with this policy. Non-audit services that are prohibited include:

1. Bookkeeping and other services related to the preparation of accounting records or financial statements of the Company or its subsidiaries.
2. Financial information systems design and implementation.
3. Appraisal or valuation services, fairness opinions, or contribution-in-kind reports.
4. Actuarial services.
5. Internal audit outsourcing services.
6. Management functions or human resources.
7. Broker or dealer, investment adviser, or investment banking services.
8. Legal services or expert services unrelated to financial statement audits.
9. Any other service that the Public Company Accounting Oversight Board determines, by regulation, is impermissible.

B. Effective January 1, 2003, officers of the Company (including its subsidiaries) may not engage the independent auditor to perform any personal services, such as personal financial planning or personal income tax services.

C. All audit services (including providing comfort letters and consents in connection with securities issuances) and permissible non-audit services provided by the independent auditor must be pre-approved by the Southern Company Audit Committee.

D. Under this Policy, the Audit Committee's approval of the independent auditor's annual arrangements letter shall constitute pre-approval for all services covered in the letter.

E. By adopting this Policy, the Audit Committee hereby pre-approves the engagement of the independent auditor to provide services related to the issuance of comfort letters and consents required for securities sales by the Company and its subsidiaries and services related to consultation on routine accounting and tax matters. The actual amounts expended for such services each calendar quarter shall be reported to the Committee at a subsequent Committee meeting.

F. The Audit Committee also delegates to its Chairman the authority to grant pre-approvals for the engagement of the independent auditor to provide any permissible service up to a limit of $50,000 per engagement. Any engagements pre-approved by the Chairman shall be presented to the full Committee at its next scheduled regular meeting.

G. The Southern Company Comptroller shall establish processes and procedures to carry out this Policy.

Approved by the Southern Company Audit Committee
December 9, 2002

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SOUTHERN COMPANY

2014 ANNUAL REPORT

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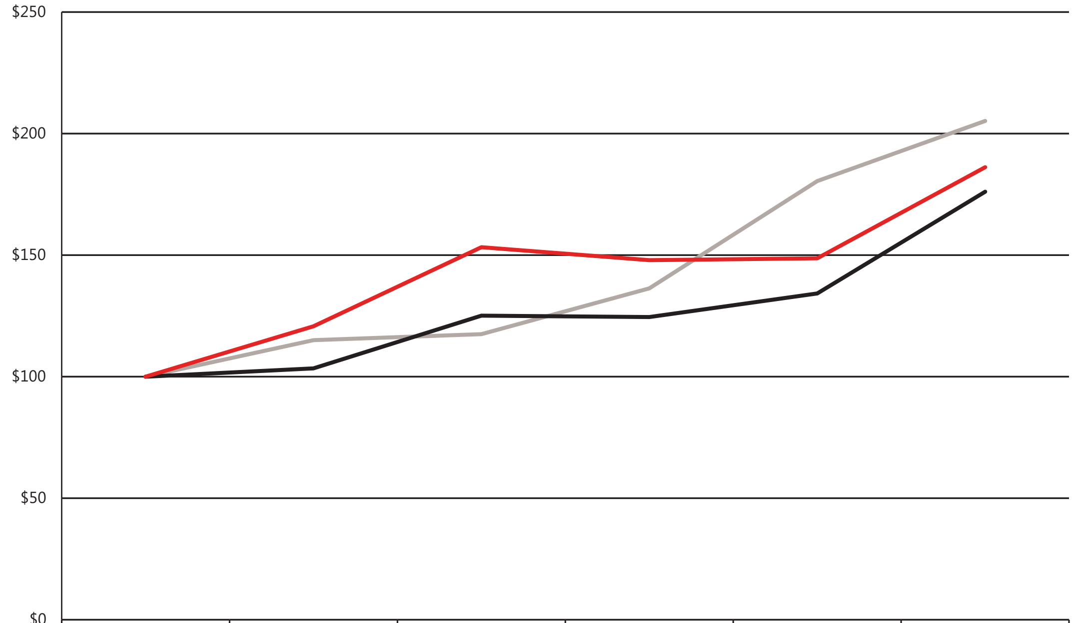
SOUTHERN COMPANY COMMON STOCK AND DIVIDEND INFORMATION

The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low	Dividend
2014			
First Quarter	$44.00	$40.27	$0.5075
Second Quarter	46.81	42.55	0.5250
Third Quarter	45.47	41.87	0.5250
Fourth Quarter	51.28	43.55	0.5250
2013			
First Quarter	$46.95	$42.82	$0.4900
Second Quarter	48.74	42.32	0.5075
Third Quarter	45.75	40.63	0.5075
Fourth Quarter	42.94	40.03	0.5075

FIVE-YEAR CUMULATIVE PERFORMANCE GRAPH

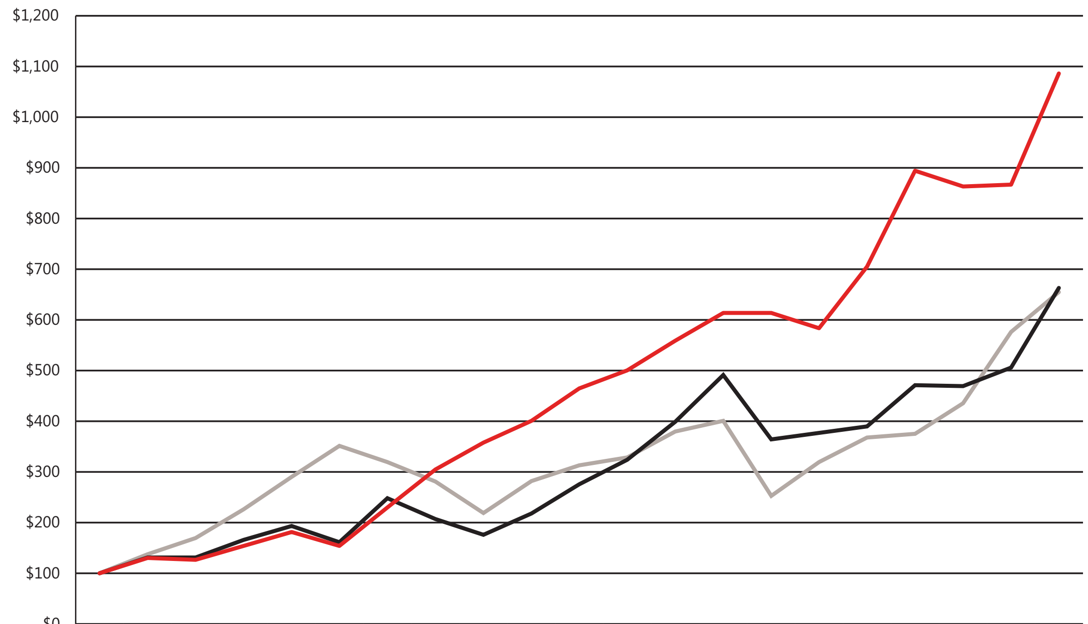
This performance graph compares the cumulative total shareholder return on the Company's common stock with the Standard & Poor's Electric Utility Index and the Standard & Poor's 500 index for the past five years. The graph assumes that $100 was invested on December 31, 2009 in the Company's common stock and each of the above indices and that all dividends were reinvested. The stockholder return shown below for the five-year historical period may not be indicative of future performance.



	2009	2010	2011	2012	2013	2014
S&P 500	100	115	117	136	180	205
S&P Electrics	100	103	125	124	134	176
Southern	100	121	153	148	149	186

TWENTY-YEAR CUMULATIVE PERFORMANCE GRAPH

This performance graph compares the cumulative total shareholder return on the Company's common stock with the Standard & Poor's Electric Utility Index and the Standard & Poor's 500 index for the past 20 years. The graph assumes that $100 was invested on December 31, 1994 in the Company's common stock and each of the above indices and that all dividends were reinvested. The distribution of shares of Mirant Corporation stock to the Company's stockholders in 2001 is treated as a special dividend for purposes of calculating the Company's shareholder return. The stockholder return shown below for the twenty-year historical period may not be indicative of future performance.



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
S&P 500	100	138	169	226	290	351	319	281	219	282	313	328	380	401	252	319	367	375	435	576	655
S&P Electrics	100	131	131	166	193	161	248	206	175	217	275	323	399	491	364	377	389	471	469	505	663
Southern	100	130	126	153	181	154	229	304	358	400	465	500	558	613	613	583	705	894	863	867	1086

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

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

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2014.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2014. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

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

Art P. Beattie
Executive Vice President and Chief Financial Officer

March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. We also have audited the Company's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page D-1). 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 D-36 to D-101) 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.

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
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

DEFINITIONS (continued)

Term	Meaning
SMEPA	South Mississippi Electric Power Association
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the Southern Company system, which consists of the traditional operating companies, Southern Power, and other direct and indirect subsidiaries. The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

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

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

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

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

Key Performance Indicators

In striving to achieve superior risk-adjusted returns while providing cost-effective energy to more than four million customers, the Southern Company system continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, execution of major construction projects, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

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

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

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

* Does not reflect EPS as calculated in accordance with GAAP. The non-GAAP measure of EPS, excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the 2015 Mississippi Supreme Court decision, is calculated by excluding from EPS, as

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

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

Earnings

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

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

Basic EPS was $2.19 in 2014, $1.88 in 2013, and $2.70 in 2012. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.18 in 2014, $1.87 in 2013, and $2.67 in 2012. EPS for 2014 was negatively impacted by $0.06 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.0825 in 2014, $2.0125 in 2013, and $1.9425 in 2012. In January 2015, Southern Company declared a quarterly dividend of 52.50 cents per share. This is the 269th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2014, the actual dividend payout ratio was 95%, while the payout ratio of net income excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the 2015 Mississippi Supreme Court decision was 74%.

RESULTS OF OPERATIONS

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

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

Electricity Business

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

A condensed statement of income for the electricity business follows:

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

Electric Operating Revenues

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

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

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

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

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate CNP," "– Georgia Power – Rate Plans," and "– Gulf Power – Retail Base Rate Case" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

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

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs (other than solar PPAs) have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Wholesale revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale revenues from power sales were as follows:

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

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

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

Other Electric Revenues

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

Energy Sales

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

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

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

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 5.2 billion KWHs in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by a decrease in customer usage. The increase in industrial KWH energy sales was primarily due to increased sales in the primary metals, chemicals, paper, non-manufacturing, transportation, and stone, clay, and glass sectors. Weather-adjusted commercial KWH energy sales decreased primarily due to decreased customer usage, partially offset by customer growth. Weather-adjusted residential KWH energy sales were flat compared to the prior year as a result of customer growth offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

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

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

Fuel and Purchased Power Expenses

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

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

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

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

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

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

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

Fuel

In 2014, fuel expense was $6.0 billion, an increase of $495 million, or 9.0%, as compared to the prior year. The increase was primarily due to a 12.7% increase in the volume of KWHs generated by coal, a 10.3% increase in the average cost of natural gas per KWH generated, and a 30.7% decrease in the volume of KWHs generated by hydro facilities resulting from less rainfall, partially offset by a 5.0% decrease in the average cost of coal per KWH generated.

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

Purchased Power

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

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

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

Other Operations and Maintenance Expenses

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

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

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

Depreciation and Amortization

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

Depreciation and amortization increased $114 million, or 6.4%, in 2013 as compared to the prior year primarily due to additional plant in service related to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and six Southern Power plants between June 2012 and October 2013, certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service) at Georgia Power, and additional transmission and distribution projects. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" for additional information on Georgia Power's unit retirement decisions. These increases were partially offset by a net reduction in amortization primarily related to amortization of a regulatory liability for state income tax credits at Georgia Power and by the deferral of certain expenses under an accounting order at Alabama Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Compliance and Pension Cost Accounting Order" for additional information on Alabama Power's accounting order.

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

Taxes Other Than Income Taxes

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

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

Estimated Loss on Kemper IGCC

In 2014 and 2013, estimated probable losses on the Kemper IGCC of $868 million and $1.2 billion, respectively, were recorded at Southern Company. These losses reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). See FUTURE EARNINGS POTENTIAL – "Construction Program" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $55 million, or 28.9%, in 2014 as compared to the prior year primarily due to additional capital expenditures at the traditional operating companies, primarily related to environmental and transmission projects, as well as Mississippi Power's Kemper IGCC.

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

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

Interest Expense, Net of Amounts Capitalized

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

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

Other Income (Expense), Net

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

Income Taxes

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

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

Other Business Activities

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

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

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

Operating Revenues

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

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $27 million, or 39.7%, in 2014 as compared to the prior year. The increase was primarily due to insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC and higher operating expenses at Southern Holdings. Other operations and maintenance expenses for these other business activities decreased $9 million, or 11.7%, in 2013 as compared to the prior year. The decrease was primarily related to lower operating expenses at SouthernLINC Wireless and decreases in consulting and legal fees, partially offset by higher operating expenses at Southern Holdings and a decrease in the amount of insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC as compared to the amount received in 2012. See Note 3 to the financial statements under "Insurance Recovery" for additional information related to the litigation settlement with MC Asset Recovery, LLC.

Interest Income

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

Other Income (Expense), Net

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

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. See Note 1 under "Leveraged Leases" for additional information.

Interest Expense

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

Income Taxes

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

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4 as well as other ongoing construction projects. Other major factors include the profitability of the competitive wholesale business and successfully expanding investments in renewable energy projects. Future earnings for the electricity business in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, including the impact of ITCs, and the successful remarketing of capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the traditional operating companies and Southern Power, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

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

Environmental Statutes and Regulations

General

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the traditional operating companies had invested approximately $10.6 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $1.1 billion, $0.7 billion, and $0.3 billion for 2014, 2013, and 2012, respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $2.1 billion from 2015 through 2017, with annual totals of approximately $1.0 billion, $0.5 billion, and $0.6 billion for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order" and "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" herein and Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information on planned unit retirements and fuel conversions at Alabama Power, Georgia Power, and Mississippi Power.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Since 1990, the electric utilities have spent approximately $9.5 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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

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

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

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

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units. In March 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power believes this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units owned by Alabama Power, units co-owned with Mississippi Power, and units owned by SEGCO, which is jointly owned by Alabama Power and Georgia Power.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

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

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

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama, Florida, Georgia, Mississippi, and North Carolina) to revise their SSM provisions within 18 months after issuance of the final rule.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, certain of the traditional operating companies have developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

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

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

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

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

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

Coal Combustion Residuals

The traditional operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 22 electric generating plants. In addition to on-site storage, the traditional operating companies also sell a portion of their CCR to third parties for beneficial reuse. Individual states regulate CCR and the states in the Southern Company system's service territory each have their own regulatory requirements. Each traditional operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

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

Environmental Remediation

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

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2013 greenhouse gas emissions were approximately 102 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2014 greenhouse gas emissions on the same basis is approximately 112 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

Alabama Power

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

Rate RSE

Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

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

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 4, 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015.

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

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

Environmental Accounting Order

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

As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. Alabama Power also plans to cease using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

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

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, Alabama Power fully amortized the balance of $123 million in certain regulatory asset accounts, and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset account balances amortized as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and August 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized at December 31, 2014.

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

Non-Environmental Federal Mandated Costs Accounting Order

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

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

Georgia Power

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

Rate Plans

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

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

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

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

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

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

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," "– Coal Combustion Residuals," and "– Global Climate Issues," and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2; the State of Georgia's Multi-Pollutant Rule; and Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

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

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

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

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

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

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances. On January 20, 2015, the Georgia PSC approved the deferral of Georgia Power's next fuel case filing until at least June 30, 2015.

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

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $6.7 billion, $5.4 billion, and $4.3 billion for 2015, 2016, and 2017, respectively.

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

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

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

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

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

See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information.

Income Tax Matters

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

Bonus Depreciation

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

Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code of 1986, as amended (Internal Revenue Code) Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Through December 31, 2014, Southern Company had recorded tax benefits totaling $276 million for the Phase II credits, of which approximately $210 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. Mississippi Power currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC.

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

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

Section 174 Research and Experimental Deduction

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

Other Matters

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

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 94% of Southern Company's total operating revenues for 2014, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs, including a reasonable return on equity. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

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

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

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

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

N/A – Not applicable

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

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

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

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material. Any further cost increases and/or extensions of the in- service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Mississippi Power's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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

Recently Issued Accounting Standards

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2014 and 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2014 and December 31, 2013. Through December 31, 2014, Southern Company has incurred non-recoverable cash expenditures of $1.3 billion and is expected to incur approximately $702 million in additional non-recoverable cash expenditures through completion of the Kemper IGCC. Southern Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2015 through 2017, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Southern Company system's projected capital expenditures in that period include investments to build new generation facilities, to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, certain of the traditional operating companies and other subsidiaries voluntarily contributed an aggregate of $500 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities in 2014 totaled $5.8 billion, a decrease of $282 million from 2013. Significant changes in operating cash flow for 2014 as compared to 2013 include $500 million of voluntary contributions to the qualified pension plan and an increase in receivables due to under recovered fuel costs, partially offset by an increase in accrued compensation. Net cash provided from operating activities in 2013 totaled $6.1 billion, an increase of $1.2 billion from 2012. The most significant change in operating cash flow for 2013 as compared to 2012 was a decrease in fossil fuel stock due to an increase in KWH generation.

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

Net cash provided from financing activities totaled $644 million in 2014 due to issuances of long-term debt and common stock, partially offset by common stock dividend payments, redemptions of long-term debt, and a reduction in short-term debt. Net cash used for financing activities totaled $324 million in 2013 due to redemptions of long-term debt and payments of common stock dividends, partially offset by issuances of long-term debt and common stock and an increase in notes payable. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

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

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

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flow, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2015, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements.

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

On February 20, 2014, Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and also are secured by a first priority lien on (i) Georgia Power's 45.7% ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, Georgia Power may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

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

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the commercial operation of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

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

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

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

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

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

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

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $1.8 billion. In addition, at December 31, 2014, the traditional operating companies had $476 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of Georgia Power were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions.

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

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014:					
Commercial paper	**$ 803**	**0.3%**	**$ 754**	**0.2%**	**$ 1,582**
Short-term bank debt	**—**	**—%**	**98**	**0.8%**	**400**
Total	**$ 803**	**0.3%**	**$ 852**	**0.3%**	
December 31, 2013:					
Commercial paper	$ 1,082	0.2%	$ 993	0.3%	$ 1,616
Short-term bank debt	400	0.9%	107	0.9%	400
Total	$ 1,482	0.4%	$ 1,100	0.3%	
December 31, 2012:					
Commercial paper	$ 820	0.3%	$ 550	0.3%	$ 938
Short-term bank debt	—	—%	116	1.2%	300
Total	$ 820	0.3%	$ 666	0.5%	

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

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

Financing Activities

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

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

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

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

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

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

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

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

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

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

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

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

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

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion on February 20, 2014 and $200 million on December 11, 2014. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029 and is expected to be reset from time to time thereafter through 2044. The interest rate applicable to the $200 million advance in December 2014 is 3.002% for an interest period that extends to 2044. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the borrowings in 2014 under the FFB Credit Facility were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of Georgia Power or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

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

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

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

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

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

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

Credit Rating Risk

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

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, interest rate derivatives, and construction of new generation at Plant Vogtle Units 3 and 4.

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

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

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

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

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2014 have a notional amount of $2.1 billion and are related to fixed and floating rate obligations. The weighted average interest rate on $3.4 billion of long-term variable interest rate exposure at January 1, 2015 was 0.94%. If Southern Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $34 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

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

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

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

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

At December 31, 2014 and 2013, substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

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

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

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to be $6.7 billion for 2015, $5.4 billion for 2016, and $4.3 billion for 2017, which includes expenditures related to the construction and start-up of the Kemper IGCC of $801 million for 2015 and $132 million for 2016. The amounts related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC for approximately $596 million (including construction costs for all prior periods relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $1.0 billion, $0.5 billion, and $0.6 billion for 2015, 2016, and 2017, respectively. The Southern Company system's amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

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

In addition, the construction program includes the development and construction of new generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC).

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

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

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

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

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

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

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(g) Primarily includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.

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

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

(j) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP for Georgia Power. Alabama Power also has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

Cautionary Statement Regarding Forward-Looking Statements

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

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any PSC requirements and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;

- investment performance of Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between Mississippi Power and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's or any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by Southern Company from time to time with the SEC.

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

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

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

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
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	2014	2013	2012
		(in millions)	
Consolidated Net Income	**$ 2,031**	$ 1,710	$ 2,415
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(6), $-, and $(7), respectively	**(10)**	—	(12)
Reclassification adjustment for amounts included in net income, net of tax of $3, $5, and $7, respectively	**5**	9	11
Marketable securities:			
Change in fair value, net of tax of $-, $(2), and $-, respectively	**—**	(3)	—
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(32), $22, and $(2), respectively	**(51)**	36	(3)
Reclassification adjustment for amounts included in net income, net of tax of $2, $4, and $(4), respectively	**3**	6	(8)
Total other comprehensive income (loss)	**(53)**	48	(12)
Dividends on preferred and preference stock of subsidiaries	**(68)**	(66)	(65)
Consolidated Comprehensive Income	**$ 1,910**	$ 1,692	$ 2,338

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

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

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

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

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

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

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

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

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

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)*	
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
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	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock							
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interest	Total
	(in thousands)		*(in millions)*							
Balance at December 31, 2011	865,664	(539)	$ 4,328	$ 4,410	$ (17)	$ 8,968	$ (111)	$ 707	$ —	$ 18,285
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,350	—	—	—	2,350
Other comprehensive income (loss)	—	—	—	—	—	—	(12)	—	—	(12)
Stock issued	12,139	—	61	336	—	—	—	—	—	397
Stock repurchased, at cost	—	(9,440)	—	—	(430)	—	—	—	—	(430)
Stock-based compensation	—	—	—	106	—	—	—	—	—	106
Cash dividends of $1.9425 per share	—	—	—	—	—	(1,693)	—	—	—	(1,693)
Other	—	(56)	—	3	(3)	1	—	—	—	1
Balance at December 31, 2012	877,803	(10,035)	4,389	4,855	(450)	9,626	(123)	707	—	19,004
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,644	—	—	—	1,644
Other comprehensive income (loss)	—	—	—	—	—	—	48	—	—	48
Stock issued	14,930	4,443	72	441	203	—	—	49	—	765
Stock-based compensation	—	—	—	65	—	—	—	—	—	65
Cash dividends of $2.0125 per share	—	—	—	—	—	(1,762)	—	—	—	(1,762)
Other	—	(55)	—	1	(3)	2	—	—	—	—
Balance at December 31, 2013	**892,733**	**(5,647)**	**4,461**	**5,362**	**(250)**	**9,510**	**(75)**	**756**	**—**	**19,764**
Net income after dividends on preferred and preference stock of subsidiaries	**—**	**—**	**—**	**—**	**—**	**1,963**	**—**	**—**	**—**	**1,963**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(53)**	**—**	**—**	**(53)**
Stock issued	**15,769**	**4,996**	**78**	**501**	**227**	**—**	**—**	**—**	**—**	**806**
Stock-based compensation	**—**	**—**	**—**	**86**	**—**	**—**	**—**	**—**	**—**	**86**
Cash dividends of $2.0825 per share	**—**	**—**	**—**	**—**	**—**	**(1,866)**	**—**	**—**	**—**	**(1,866)**
Contributions from noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**221**	**221**
Net income attributable to noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(2)**	**(2)**
Other	**—**	**(74)**	**—**	**6**	**(3)**	**2**	**—**	**—**	**2**	**7**
Balance at December 31, 2014	**908,502**	**(725)**	**$ 4,539**	**$ 5,955**	**$ (26)**	**$ 9,609**	**$ (128)**	**$ 756**	**$ 221**	**$ 20,926**

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

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (Southern Company or the Company) is the parent company of four traditional operating companies, Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment, but is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the FERC, and the traditional operating companies are also subject to regulation by their respective state PSCs. The companies follow GAAP in the U.S. and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards

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

Regulatory Assets and Liabilities

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

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

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

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

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

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

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which may range up to 50 years.

(d) Recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

(e) Recovered over the life of the PPA for periods up to nine years.

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

(g) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods not exceeding 10 years.

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

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

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

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

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

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

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

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

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

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

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Southern Company's electric utility subsidiaries have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with regulatory requirements, deferred federal ITCs for the traditional operating companies are amortized over the average lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $22 million in 2014, $16 million in 2013, and $23 million in 2012. At December 31, 2014, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years. Additionally, several subsidiaries have state ITCs, which are recognized in the period in which the credit is claimed on the state income tax return. A portion of the state ITCs available to reduce state income taxes payable was not utilized currently and will be carried forward and utilized in future years.

Under the American Recovery and Reinvestment Act of 2009 and the American Taxpayer Relief Act of 2012 (ATRA), certain projects at Southern Power are eligible for federal ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $11.4 million in 2014, $5.5 million in 2013, and $2.6 million in 2012. Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $74 million, $158 million, and $45 million for the years ended December 31, 2014, 2013, and 2012, respectively, which had a material impact on cash flows. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $48 million in 2014, $31 million in 2013, and $8 million in 2012.

In accordance with accounting standards related to the uncertainty in income taxes, Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

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

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

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power's Plant Farley and Georgia Power's Plants Hatch and Vogtle Units 1 and 2 range from 18 to 24 months, depending on the unit.

Assets acquired under a capital lease are included in property, plant, and equipment and are further detailed in the table below:

	Asset Balances at December 31,	
	2014	2013
	(in millions)	
Office building	**$ 61**	$ 61
Nitrogen plant	**83**	83
Computer-related equipment	**60**	62
Gas pipeline	**6**	6
Less: Accumulated amortization	**(49)**	(48)
Balance, net of amortization	**$ 161**	$ 164

The amount of non-cash property additions recognized for the years ended December 31, 2014, 2013, and 2012 was $528 million, $411 million, and $524 million, respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2014, 2013, and 2012 was $25 million, $107 million, and $14 million, respectively.

Acquisitions

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

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

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

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

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

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

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

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

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.1% in 2014, 3.3% in 2013, and 3.2% in 2012. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $23.5 billion and $22.5 billion at December 31, 2014 and 2013, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Certain of Southern Power's generation assets are now depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. Cost, net of salvage value, of these assets is depreciated on an hours or starts units-of-production basis. The book value of plant-in-service as of December 31, 2014 that is depreciated on a units-of-production basis was approximately $470.2 million.

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

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years. Accumulated depreciation for other plant in service totaled $533 million and $513 million at December 31, 2014 and 2013, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Southern Company system's nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Southern Company system has retirement obligations related to various landfill sites, ash ponds, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

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

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

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

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2014 and 2013, approximately $51 million and $32 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $52 million and $33 million at December 31, 2014 and 2013, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2014, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $886 million, debt securities of $638 million, and $19 million of other securities. At December 31, 2013, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $896 million, debt securities of $528 million, and $40 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

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

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

At December 31, 2014 and 2013, the accumulated provisions for decommissioning were as follows:

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

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2014 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2012 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2068	2072
		(in millions)	
Site study costs:			
Radiated structures	$ 1,362	$ 549	$ 453
Spent fuel management	—	131	115
Non-radiated structures	80	51	76
Total site study costs	$ 1,442	$ 731	$ 644

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved Georgia Power's annual decommissioning cost through 2016 for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

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

Allowance for Funds Used During Construction and Interest Capitalized

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

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

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $40 million in 2014 and $28 million in 2013. Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2014 and 2013, there were no such additional accruals. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" and "Retail Regulatory Matters – Georgia Power – Storm Damage Recovery" for additional information regarding Alabama Power's NDR and Georgia Power's deferred storm costs, respectively.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

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

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

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

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

Southern Company and its subsidiaries use derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Southern Company system's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel-hedging programs result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2014, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

Accumulated OCI (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
			(in millions)	
Balance at December 31, 2013	$ (36)	$ —	$ (39)	$ (75)
Current period change	(5)	—	(48)	(53)
Balance at December 31, 2014	**$ (41)**	**$ —**	**$ (87)**	**$ (128)**

2014 ANNUAL REPORT

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014, certain of the traditional operating companies and other subsidiaries voluntarily contributed an aggregate of $500 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2015, other postretirement trust contributions are expected to total approximately $19 million.

Actuarial Assumptions

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

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

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

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

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

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

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2014 as follows:

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

Pension Plans

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

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

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

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

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

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2014 and 2013 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2015.

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

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

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

Components of net periodic pension cost were as follows:

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

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2014, estimated benefit payments were as follows:

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

Other Postretirement Benefits

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

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

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

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

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2014 and 2013 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2015.

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

NOTES (continued)

The components of OCI, along with the changes in the balance of net regulatory assets (liabilities), related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

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

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

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

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

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

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

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

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	42%	**41%**	40%
International equity	21	**23**	25
Domestic fixed income	24	**26**	24
Global fixed income	4	**3**	4
Special situations	1	**—**	—
Real estate investments	5	**5**	5
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income***. A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.

- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2014 and 2013. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

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

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

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

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 1,433	$ 839	$ —	$ 2,272
International equity*	1,101	1,018	—	2,119
Fixed income:				
U.S. Treasury, government, and agency bonds	—	599	—	599
Mortgage- and asset-backed securities	—	156	—	156
Corporate bonds	—	978	—	978
Pooled funds	—	471	—	471
Cash equivalents and other	1	223	—	224
Real estate investments	260	—	1,000	1,260
Private equity	—	—	571	571
Total	$ 2,795	$ 4,284	$ 1,571	$ 8,650
Liabilities:				
Derivatives	$ —	$ (3)	$ —	$ (3)
Total	$ 2,795	$ 4,281	$ 1,571	$ 8,647

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

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

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

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

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*	$ 147	$ 56	$ —	$ 203
International equity*	36	67	—	103
Fixed income:				
U.S. Treasury, government, and agency bonds	—	29	—	29
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	39	—	39
Pooled funds	—	41	—	41
Cash equivalents and other	9	27	—	36
Trust-owned life insurance	—	381	—	381
Real estate investments	11	—	37	48
Private equity	—	—	19	19
Total	$ 203	$ 646	$ 56	$ 905

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

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 157	$ 45	$ —	$ 202
International equity*	39	82	—	121
Fixed income:				
U.S. Treasury, government, and agency bonds	—	34	—	34
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	35	—	35
Pooled funds	—	46	—	46
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	369	—	369
Real estate investments	10	—	36	46
Private equity	—	—	20	20
Total	$ 206	$ 636	$ 56	$ 898

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

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

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

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014, 2013, and 2012 were $87 million, $84 million, and $82 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Insurance Recovery

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

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

Environmental Matters

New Source Review Actions

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

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

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2014 was $22 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

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

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

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

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $48 million as of December 31, 2014. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

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

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

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

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

On March 4, 2014, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2014 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Alabama Power

Rate RSE

Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range. Prior to 2014, retail rates remained unchanged when the retail ROE was projected to be between 13.0% and 14.5%.

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

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting Alabama Power's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon the WCE range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

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

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

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 4, 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015. As of December 31, 2014, Alabama Power had an under recovered certificated PPA balance of $56 million, of which $27 million is included in under recovered regulatory clause revenues and $29 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of electricity from wind-powered generating facilities that became operational in 2012. In 2012, the Alabama PSC approved and certificated a second PPA of approximately 200 MWs of electricity from other wind-powered generating facilities which became operational in 2014. The terms of the PPAs permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell the environmental attributes, separately or bundled with energy. Alabama Power has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If Alabama Power is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

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

Rate ECR

Alabama Power has established energy cost recovery rates under Alabama Power's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2015 the energy cost recovery rates which began in 2011. Therefore, the Rate ECR factor as of January 1, 2015 remained at 2.681 cents per KWH. Effective with billings beginning in January 2016, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

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

Rate NDR

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

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

Environmental Accounting Order

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

As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. Alabama Power also plans to cease using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

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

Nuclear Waste Fund Accounting Order

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

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

Compliance and Pension Cost Accounting Order

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

On November 3, 2014, the Alabama PSC issued an accounting order authorizing Alabama Power to fully amortize the balances in certain regulatory asset accounts, including the $28 million of compliance and pension costs accumulated at December 31, 2014. This amortization expense was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires

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

Non-Nuclear Outage Accounting Order

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

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

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, Alabama Power fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset account balances amortized as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, as discussed herein.

Non-Environmental Federal Mandated Costs Accounting Order

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

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

Georgia Power

Rate Plans

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

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

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

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

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

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

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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

Integrated Resource Plans

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

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

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

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

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

Fuel Cost Recovery

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

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

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, Georgia Power is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2014 and December 31, 2013, the balance in the regulatory asset related to storm damage was $98 million and $37 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $68 million and $7 million included in other regulatory assets, deferred, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

Nuclear Construction

In 2008, Georgia Power, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

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

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Georgia Power's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by Georgia Power and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

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

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

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

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

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

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

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

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

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

Gulf Power

Retail Base Rate Case

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

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

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

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

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245.3 million of grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC.

The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

Recovery of the Kemper IGCC cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions) and costs subject to the cost cap remain subject to review and approval by the Mississippi PSC. Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

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

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

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

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

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

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

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

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

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

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

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

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN. Mississippi Power expects the Mississippi PSC to apply operational parameters in connection with the evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or Mississippi Power incurs additional costs to satisfy such parameters, there could be a material adverse impact on the financial statements.

2013 Settlement Agreement

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that, among other things, established the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The 2013 Settlement Agreement also allowed Mississippi Power to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in February 2013. Mississippi Power's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

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

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC Rate Order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continues to record AFUDC on the Kemper IGCC through the in-service date. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

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

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

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, Mississippi Power had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. Mississippi Power is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying Mississippi Power's request for rehearing. Mississippi Power is also evaluating its regulatory options.

Rate Mitigation Plan

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

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

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

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

Prudence Reviews

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

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

On August 18, 2014, Mississippi Power requested confirmation by the Mississippi PSC of Mississippi Power's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million. The projected balance at March 31, 2016 is estimated to total approximately $269.8 million. The amortization period of 40 years proposed by Mississippi Power for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. Mississippi Power is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. Mississippi Power is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million.

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

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

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

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

Proposed Sale of Undivided Interest to SMEPA

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

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

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

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

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

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

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. In the 2015 Mississippi Supreme Court decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Investment Tax Credits and Bonus Depreciation

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Through December 31, 2014, Mississippi Power had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210.0 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. Mississippi Power currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

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

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

Section 174 Research and Experimental Deduction

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

Other Matters

Sierra Club Settlement Agreement

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

Under the Sierra Club Settlement Agreement, Mississippi Power agreed to, among other things, fund a $15 million grant payable over a 15-year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, Mississippi Power paid $7 million in 2014, recognized in other income (expense), net in Southern Company's statement of income. In addition, and consistent with Mississippi Power's ongoing evaluation of recent environmental rules and regulations, Mississippi Power agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. Mississippi Power also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with PowerSouth Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light

Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Duke Energy Florida, Inc. for a combustion turbine unit at Intercession City, Florida. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2014, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Plant Vogtle (nuclear) Units 1 and 2	45.7%	$ 3,420	$ 2,059	$ 46
Plant Hatch (nuclear)	50.1	1,117	559	66
Plant Miller (coal) Units 1 and 2	91.8	1,512	561	14
Plant Scherer (coal) Units 1 and 2	8.4	254	83	1
Plant Wansley (coal)	53.5	856	278	15
Rocky Mountain (pumped storage)	25.4	182	124	2
Intercession City (combustion turbine)	33.3	14	5	—
Plant Stanton (combined cycle) Unit A	65.0	157	47	—

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

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly-owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

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

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

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

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 11,125**	$ 9,710
Property basis differences	**1,332**	1,515
Leveraged lease basis differences	**299**	287
Employee benefit obligations	**613**	491
Premium on reacquired debt	**103**	113
Regulatory assets associated with employee benefit obligations	**1,390**	705
Regulatory assets associated with AROs	**871**	824
Other	**523**	350
Total	**16,256**	13,995
Deferred tax assets —		
Federal effect of state deferred taxes	**430**	421
Employee benefit obligations	**1,675**	1,048
Over recovered fuel clause	**—**	30
Other property basis differences	**453**	157
Deferred costs	**86**	84
ITC carryforward	**480**	121
Unbilled revenue	**67**	116
Other comprehensive losses	**89**	54
AROs	**871**	824
Estimated Loss on Kemper IGCC	**631**	472
Deferred state tax assets	**117**	77
Other	**342**	220
Total	**5,241**	3,624
Valuation allowance	**(49)**	(49)
Total deferred tax assets	**5,192**	3,575
Total deferred tax liabilities, net	**11,064**	10,420
Portion included in current assets/(liabilities), net	**504**	143
Accumulated deferred income taxes	**$ 11,568**	$ 10,563

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2014, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $701 million, which could result in net state income tax benefits of $41 million, if utilized. However, the subsidiaries have established a valuation allowance for the entire amount due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2018 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2014, the tax-related regulatory assets to be recovered from customers were $1.5 billion. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2014, the tax-related regulatory liabilities to be credited to customers were $192 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $22 million in 2014, $16 million in 2013, and $23 million in 2012. At December 31, 2014, Southern Company had a federal ITC carryforward which is expected to result in $379 million of federal income tax benefit. The ITC carryforward expires in 2023, but is expected to be utilized in 2015. Additionally, Southern Company had state ITC carryforwards for the states of Georgia and Mississippi totaling $159 million, which will expire between 2020 and 2024.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.3**	2.5	2.5
Employee stock plans dividend deduction	**(1.4)**	(1.6)	(1.0)
Non-deductible book depreciation	**1.4**	1.5	0.9
AFUDC-Equity	**(2.9)**	(2.6)	(1.3)
ITC basis difference	**(1.6)**	(1.2)	(0.3)
Other	**(0.3)**	(0.5)	(0.2)
Effective income tax rate	**32.5%**	33.1%	35.6%

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity. The 2014 effective tax rate decrease, as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity and an increase in tax benefits related to federal ITCs. Additionally, the 2013 effective rate decrease, as compared to 2012, is primarily due to an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 7**	$ 70	$ 120
Tax positions increase from current periods	**64**	3	13
Tax positions increase from prior periods	**102**	—	7
Tax positions decrease from prior periods	**(3)**	(66)	(56)
Reductions due to settlements	**—**	—	(10)
Reductions due to expired statute of limitations	**—**	—	(4)
Balance at end of year	**$ 170**	$ 7	$ 70

The tax positions increase from current periods and increase from prior periods for 2014 relate primarily to a deduction for R&E expenditures related to the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Section 174 Research and Experimental Deduction" for more information. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on Southern Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in millions)	
Tax positions impacting the effective tax rate	**$ 10**	$ 7	$ 5
Tax positions not impacting the effective tax rate	**160**	—	65
Balance of unrecognized tax benefits	**$ 170**	$ 7	$ 70

The tax positions impacting the effective tax rate for 2014, 2013, and 2012 relate to federal and state income tax credits. The tax positions not impacting the effective tax rate for 2014 relate to a deduction for R&E expenditures related to the Kemper IGCC. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Southern Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. Southern Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2008.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2014 and 2013, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At each of December 31, 2014 and 2013, trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2014	2013
	(in millions)	
Senior notes	**$ 2,375**	$ 428
Other long-term debt	**775**	12
Pollution control revenue bonds	**152**	—
Capitalized leases	31	29
Total	**$ 3,333**	$ 469

Maturities through 2019 applicable to total long-term debt are as follows: $3.33 billion in 2015; $1.83 billion in 2016; $1.55 billion in 2017; $862 million in 2018; and $1.21 billion in 2019.

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

Bank Term Loans

Southern Company and certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month LIBOR. At December 31, 2014, Mississippi Power had outstanding bank term loans totaling $775 million, which are reflected in the statements of capitalization as long-term debt. At December 31, 2013, Mississippi Power had outstanding bank term loans totaling $525 million and Georgia Power had outstanding bank term loans totaling $400 million.

In January 2014, Mississippi Power entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

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

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

The outstanding bank loans as of December 31, 2014, all of which relate to Mississippi Power, have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014, Mississippi Power was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of Georgia Power under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, Georgia Power, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which Georgia Power may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility will be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.

All borrowings under the FFB Credit Facility are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power’s reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power’s 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power’s rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power’s ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375%.

On February 20, 2014, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE’s consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB’s commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

Senior Notes

Southern Company and its subsidiaries issued a total of $1.4 billion of senior notes in 2014. Southern Company issued $750 million and its subsidiaries issued a total of $600 million. The proceeds of these issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs.

At December 31, 2014 and 2013, Southern Company and its subsidiaries had a total of $18.2 billion and $17.3 billion, respectively, of senior notes outstanding. At December 31, 2014 and 2013, Southern Company had a total of $2.2 billion and $1.8 billion, respectively, of senior notes outstanding.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.2 billion of outstanding pollution control revenue bonds at December 31, 2014 and 2013. The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. See "Assets Subject to Lien" herein for additional information.

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of Mississippi Power. In May 2014 and August 2014, the MBFC issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of Mississippi Power and proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2014 and 2013. Mississippi Power had no obligation at December 31, 2014 and $11.3 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Mississippi Power's agreements relating to its taxable revenue bonds include covenants limiting debt levels consistent with those described above under "Bank Term Loans."

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service and the related obligations are classified as long-term debt.

In September 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2014 of approximately $80 million with an annual interest rate of 4.9%. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

At December 31, 2014 and 2013, the capitalized lease obligations for Georgia Power's corporate headquarters building were $40 million and $45 million, respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2014 and 2013, Alabama Power had a capitalized lease obligation of $5 million for a natural gas pipeline with an annual interest rate of 6.9%.

At December 31, 2014 and 2013, a subsidiary of Southern Company had capital lease obligations of approximately $34 million and $30 million, respectively, for certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.4% to 3.2%.

Other Obligations

In 2012, January 2014, and October 2014, Mississippi Power received $150 million, $75 million, and $50 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $41 million as of December 31, 2014.

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See "Plant Daniel Revenue Bonds" herein for additional information.

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of Georgia Power that are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

Bank Credit Arrangements

At December 31, 2014, committed credit arrangements with banks were as follows:

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

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^{1}/_{4}$ of 1% for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

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

Most of these bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities and, for Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

A portion of the $5.2 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $1.8 billion. In addition, at December 31, 2014, the traditional operating companies had $476 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of Georgia Power were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" for additional information.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	**Weighted Average Interest Rate**
	(in millions)	
December 31, 2014:		
Commercial paper	**$ 803**	**0.3%**
Short-term bank debt	**—**	**—%**
Total	**$ 803**	**0.3%**
December 31, 2013:		
Commercial paper	$ 1,082	0.2%
Short-term bank debt	400	0.9%
Total	$ 1,482	0.4%

Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "noncontrolling interest," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

There were no changes for the years ended December 31, 2014 and 2013 in redeemable preferred stock of subsidiaries for Southern Company.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the traditional operating companies and Southern Power incurred fuel expense of $6.0 billion, $5.5 billion, and $5.1 billion, respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.

In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $198 million, $157 million, and $171 million for 2014, 2013, and 2012, respectively.

Estimated total obligations under these commitments at December 31, 2014 were as follows:

	Operating Leases (1)	Other
	(in millions)	
2015	$ 230	$ 11
2016	234	11
2017	264	10
2018	270	7
2019	274	6
2020 and thereafter	1,980	50
Total	$ 3,252	$ 95

(1) A total of $1.1 billion of biomass PPAs included under operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $118 million, $123 million, and $155 million for 2014, 2013, and 2012, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2015	$ 50	$ 50	$ 100
2016	41	48	89
2017	18	47	65
2018	9	35	44
2019	6	23	29
2020 and thereafter	20	228	248
Total	$ 144	$ 431	$ 575

For the traditional operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $53 million. At the termination of the leases, the lessee may renew the lease or exercise its purchase option or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

In December 2013, Georgia Power entered into an agreement that requires Georgia Power to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

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

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

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

Shares Reserved

At December 31, 2014, a total of 93 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance shares units as discussed below). Of the total 93 million shares reserved, there were 15 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2014.

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2014, there were 5,437 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2014**	2013	2012
Expected volatility	**14.6%**	16.6%	17.7%
Expected term *(in years)*	**5**	5	5
Interest rate	**1.5%**	0.9%	0.9%
Dividend yield	**4.9%**	4.4%	4.2%
Weighted average grant-date fair value	**$2.20**	$2.93	$3.39

Southern Company's activity in the stock option program for 2014 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2013	38,819,366	$38.64
Granted	12,812,691	41.40
Exercised	11,585,363	35.06
Cancelled	117,375	42.72
Outstanding at December 31, 2014	**39,929,319**	**$40.55**
Exercisable at December 31, 2014	**20,695,310**	**$38.76**

The number of stock options vested, and expected to vest in the future, as of December 31, 2014 was not significantly different from the number of stock options outstanding at December 31, 2014 as stated above. As of December 31, 2014, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately seven years and six years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $342 million and $214 million, respectively.

As of December 31, 2014, there was $10 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 16 months.

For the years ended December 31, 2014, 2013, and 2012, total compensation cost for stock option awards recognized in income was $27 million, $25 million, and $23 million, respectively, with the related tax benefit also recognized in income of $10 million, $10 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $125 million, $77 million, and $162 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $48 million, $30 million, and $62 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2014, 2013, and 2012 was $400 million, $204 million, and $397 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2014	2013	2012
Expected volatility	**12.6%**	12.0%	16.0%
Expected term *(in years)*	**3**	3	3
Interest rate	**0.6%**	0.4%	0.4%
Annualized dividend rate	**$2.03**	$1.96	$1.89
Weighted average grant-date fair value	**$37.54**	$40.50	$41.99

Total unvested performance share units outstanding as of December 31, 2013 were 1,643,759. During 2014, 1,057,813 performance share units were granted, 755,716 performance share units were vested, and 115,475 performance share units were forfeited, resulting in 1,830,381 unvested units outstanding at December 31, 2014. In January 2015, the vested performance share award units were converted into 105,783 shares outstanding at a share price of $49.71 for the three-year performance and vesting period ended December 31, 2014.

For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $33 million, $31 million, and $28 million, respectively, with the related tax benefit also recognized in income of $13 million, $12 million, and $11 million, respectively. As of December 31, 2014, there was $37 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2014	2013	2012
		(in millions)	
As reported shares	**897**	877	871
Effect of options and performance share award units	**4**	4	8
Diluted shares	**901**	881	879

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were $7 million and $16 million as of December 31, 2014 and 2013, respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2014, consolidated retained earnings included $6.4 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $247 million, respectively, per incident, but not more than an aggregate of $38 million and $37 million, respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 herein for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. On April 1, 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $50 million and $72 million, respectively.

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

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

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

10. FAIR VALUE MEASUREMENTS

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

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

NOTES (continued)

As of December 31, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 13	$ —	$ 13
Interest rate derivatives	—	8	—	8
Nuclear decommissioning trusts:[a]				
Domestic equity	583	85	—	668
Foreign equity	34	184	—	218
U.S. Treasury and government agency securities	—	130	—	130
Municipal bonds	—	62	—	62
Corporate bonds	—	299	—	299
Mortgage and asset backed securities	—	139	—	139
Other	11	13	3	27
Cash equivalents	397	—	—	397
Other investments	9	—	1	10
Total	$ 1,034	$ 933	$ 4	$ 1,971
Liabilities:				
Energy-related derivatives	$ —	$ 201	$ —	$ 201
Interest rate derivatives	—	24	—	24
Total	$ —	$ 225	$ —	$ 225

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

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:				
Energy-related derivatives	$ —	$ 24	$ —	$ 24
Interest rate derivatives	—	3	—	3
Nuclear decommissioning trusts:[(a)]				
Domestic equity	589	75	—	664
Foreign equity	35	196	—	231
U.S. Treasury and government agency securities	—	103	—	103
Municipal bonds	—	64	—	64
Corporate bonds	—	229	—	229
Mortgage and asset backed securities	—	132	—	132
Other	—	37	3	40
Cash equivalents	491	—	—	491
Other investments	9	—	4	13
Total	$ 1,124	$ 863	$ 7	$ 1,994
Liabilities:				
Energy-related derivatives	$ —	$ 56	$ —	$ 56

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source.

A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgment, are also obtained when available.

Investments in private equity and real estate within the nuclear decommissioning trusts are generally classified as Level 3, as the underlying assets typically do not have observable inputs. The fund manager values these assets using various inputs and techniques depending on the nature of the underlying investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

"Other investments" include investments that are not traded in the open market. The fair value of these investment have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity funds	$ 121	None	Monthly	5 days
Equity – commingled funds	63	None	Daily/Monthly	Daily/7 days
Debt – commingled funds	15	None	Daily	5 days
Other – commingled funds	8	None	Daily	Not applicable
Other – money market funds	11	None	Daily	Not applicable
Trust-owned life insurance	115	None	Daily	15 days
Cash equivalents:				
Money market funds	397	None	Daily	Not applicable
As of December 31, 2013:				
Nuclear decommissioning trusts:				
Foreign equity funds	$ 131	None	Monthly	5 days
Corporate bonds – commingled funds	8	None	Daily	Not applicable
Equity – commingled funds	65	None	Daily/Monthly	Daily/7 days
Other – commingled funds	24	None	Daily	Not applicable
Trust-owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	491	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have the Funds to comply with the NRC's regulations. The foreign equity fund in Georgia Power's nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities, depositary receipts, including American depositary receipts, European depositary receipts, and global depositary receipts; and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The other-commingled funds and other-money market funds in Georgia Power's nuclear decommissioning trusts are invested primarily in a diversified portfolio of high quality, short-term, liquid debt securities. The funds represent the cash collateral received under the Funds' managers' securities lending program and/or the excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the funds. See Note 1 under "Nuclear Decommissioning" for additional information.

Alabama Power's nuclear decommissioning trusts include investments in TOLI. The taxable nuclear decommissioning trusts invest in the TOLI in order to minimize the impact of taxes on the portfolios and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trusts do not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. These commingled funds, along with other equity and debt commingled funds held in Alabama Power's nuclear decommissioning trusts, primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection. See Note 1 under "Nuclear Decommissioning" for additional information.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2014	**$ 24,015**	**$ 25,816**
2013	$ 21,650	$ 22,197

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 herein for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in commodity fuel prices and prices of electricity because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales from its uncontracted generating capacity. Further, the traditional operating companies may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted wholesale generating capacity is used to sell electricity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 244 million mmBtu for the Southern Company system, with the longest hedge date of 2019 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2017 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 6 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial for Southern Company.

Interest Rate Derivatives

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

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

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$200	3-month LIBOR	2.93%	October 2025	$ (8)
	350	3-month LIBOR	2.57%	May 2025	(6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	1
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$2,050				$ (16)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Any ineffectiveness is recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. At December 31, 2014, there were no foreign currency derivatives outstanding.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 7**	$ 16	Other current liabilities	**$ 118**	$ 26
	Other deferred charges and assets	**—**	7	Other deferred credits and liabilities	**79**	29
Total derivatives designated as hedging instruments for regulatory purposes		**$ 7**	$ 23		**$ 197**	$ 55
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 7**	$ 3	Other current liabilities	**$ 17**	$ —
	Other deferred charges and assets	**1**	—	Other deferred credits and liabilities	**7**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 8**	$ 3		**$ 24**	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives	Other current assets	**$ 6**	$ —	Other current liabilities	**$ 4**	$ 1
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**—**	—
Total derivatives not designated as hedging instruments		**$ 6**	$ 1		**$ 4**	$ 1
Total		**$ 21**	$ 27		**$ 225**	$ 56

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

Fair Value					
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 13**	$ 24	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 201**	$ 56
Gross amounts not offset in the Balance Sheet [(b)]	**(9)**	(22)	Gross amounts not offset in the Balance Sheet [(b)]	**(9)**	(22)
Net energy-related derivative assets	**$ 4**	$ 2	**Net energy-related derivative liabilities**	**$ 192**	$ 34
Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 8**	$ 3	Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 24**	$ —
Gross amounts not offset in the Balance Sheet [(b)]	**(8)**	—	Gross amounts not offset in the Balance Sheet [(b)]	**(8)**	—
Net interest rate derivative assets	**$ —**	$ 3	**Net interest rate derivative liabilities**	**$ 16**	$ —

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (118)**	$ (26)	Other regulatory liabilities, current	**$ 7**	$ 16
	Other regulatory assets, deferred	**(79)**	(29)	Other regulatory liabilities, deferred	**—**	7
Total energy-related derivative gains (losses)		**$(197)**	$(55)		**$ 7**	$ 23

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for Southern Company. Furthermore, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes to the carrying value of long-term debt and the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from OCI into earnings were immaterial for Southern Company.

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related and foreign currency derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company.

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses was associated with hedging fuel price risk of certain PPA customers and had no impact on net income or on fuel expense as presented in the Company's statements of income for the years ended December 31, 2014, 2013, and 2012. This third party hedging activity has been discontinued.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2014, Southern Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $54 million. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

Southern Company, the traditional operating companies, and Southern Power are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional operating companies, and Southern Power only enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Southern Company, the traditional operating companies, and Southern Power have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional operating companies', and Southern Power's exposure to counterparty credit risk. Therefore, Southern Company, the traditional operating companies, and Southern Power do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies – Alabama Power, Georgia Power, Gulf Power and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Southern Company's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $383 million, $346 million, and $425 million in 2014, 2013, and 2012, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2014, 2013, and 2012 was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2014							
Operating revenues	**$ 17,354**	**$ 1,501**	**$ (449)**	**$ 18,406**	**$ 159**	**$ (98)**	**$ 18,467**
Depreciation and amortization	**1,709**	**220**	**—**	**1,929**	**16**	**—**	**1,945**
Interest income	**17**	**1**	**—**	**18**	**3**	**(2)**	**19**
Interest expense	**705**	**89**	**—**	**794**	**43**	**(2)**	**835**
Income taxes	**1,056**	**(3)**	**—**	**1,053**	**(76)**	**—**	**977**
Segment net income (loss)[(a) (b)]	**1,797**	**172**	**—**	**1,969**	**(3)**	**(3)**	**1,963**
Total assets	**64,644**	**5,550**	**(131)**	**70,063**	**1,156**	**(296)**	**70,923**
Gross property additions	**5,568**	**942**	**—**	**6,510**	**11**	**1**	**6,522**
2013							
Operating revenues	$ 16,136	$ 1,275	$ (376)	$ 17,035	$ 139	$ (87)	$ 17,087
Depreciation and amortization	1,711	175	—	1,886	15	—	1,901
Interest income	17	1	—	18	2	(1)	19
Interest expense	714	74	—	788	36	—	824
Income taxes	889	46	—	935	(85)	(1)	849
Segment net income (loss)[(a) (b)]	1,486	166	—	1,652	(10)	2	1,644
Total assets	59,447	4,429	(101)	63,775	1,077	(306)	64,546
Gross property additions	5,226	633	—	5,859	9	—	5,868

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2012							
Operating revenues	$ 15,730	$ 1,186	$ (438)	$ 16,478	$ 141	$ (82)	$ 16,537
Depreciation and amortization	1,629	143	—	1,772	15	—	1,787
Interest income	21	1	—	22	19	(1)	40
Interest expense	757	63	—	820	39	—	859
Income taxes	1,307	93	—	1,400	(66)	—	1,334
Segment net income (loss)[(a)]	2,145	175	1	2,321	33	(4)	2,350
Total assets	58,600	3,780	(129)	62,251	1,116	(218)	63,149
Gross property additions	4,813	241	—	5,054	5	—	5,059

(a) After dividends on preferred and preference stock of subsidiaries.

(b) Segment net income (loss) for the traditional operating companies in 2014 and 2013 includes $868 million in pre-tax charges ($536 million after tax) and $1.2 billion in pre-tax charges ($729 million after tax), respectively, for estimated probable losses on the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2014	**$15,550**	**$2,184**	**$672**	**$18,406**
2013	14,541	1,855	639	17,035
2012	14,187	1,675	616	16,478

NOTES (continued)

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	Per Common Share: 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.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
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	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)
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	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.

1. Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Fanning, 58, joined the Company as a Financial Analyst in 1980. He has held his current position since December 2010. Previously, Fanning served as Executive Vice President and Chief Operating Officer of the Company, President and Chief Executive Officer of Gulf Power, and Chief Financial Officer of the Company, Georgia Power, and Mississippi Power.

2. Art P. Beattie
Executive Vice President and Chief Financial Officer
Beattie, 60, joined the Company in 1976 as a Junior Accountant with Alabama Power. He has held his current position since August 2010. Beattie is responsible for the Company's accounting, finance, tax, investor relations, treasury, and risk management functions. He also serves as Chief Risk Officer. Previously, Beattie served in several executive accounting and finance positions at Alabama Power, including Chief Financial Officer, Treasurer, and Comptroller.

3. W. Paul Bowers
Executive Vice President and Chairman, President, and Chief Executive Officer of Georgia Power
Bowers, 58, joined the Company as a Residential Sales Representative with Gulf Power in 1979. He has held his current position since January 2011. Previously, Bowers served as Chief Operating Officer of Georgia Power. He also served as Chief Financial Officer of the Company, President of Southern Company Generation, President and Chief Executive Officer of Southern Power, President and Chief Executive Officer of the Company's former United Kingdom subsidiary, and Senior Vice President and Chief Marketing Officer of the Company.

4. S. W. Connally, Jr.
President and Chief Executive Officer of Gulf Power
Connally, 45, joined the Company in 1989 as a Co-Op Student at Georgia Power. He has held his current position since July 2012. Previously, he served as Senior Vice President and Senior Production Officer for Georgia Power. He has served as Plant Manager at Plants Watson, Daniel, and Barry. He has also worked in Customer Operations and Sales and Marketing.

5. Mark A. Crosswhite
Executive Vice President and Chairman, President, and Chief Executive Officer of Alabama Power
Crosswhite, 52, joined the Company in 2004 as Senior Vice President and General Counsel for Southern Company Generation. He has held his current position since March 2014. He was previously Executive Vice President and Chief Operating Officer of the Company, President and Chief Executive Officer of Gulf Power, and Executive Vice President of External Affairs and Senior Vice President and General Counsel at Alabama Power. Prior to joining the Company, he was a partner in the law firm of Balch & Bingham LLP in Birmingham, Alabama, where he practiced for 17 years.

6. Kimberly S. Greene
Executive Vice President and Chief Operating Officer
Greene, 48, has held her current position since March 2014. Previously, she was President and Chief Executive Officer of Southern Company Services, Inc. Prior to that, she was employed by Tennessee Valley Authority (TVA), where she served as Chief Financial Officer, Group President of Strategy and External Relations, and Chief Generation Officer. Prior to her time at TVA, she served as Senior Vice President of Finance and Treasurer for the Company and has held various positions with Mirant Corporation, including Chief Commercial Officer, South Region.

7. G. Edison Holland, Jr.
Executive Vice President and Chairman, President, and Chief Executive Officer of Mississippi Power
Holland, 62, joined the Company as Vice President and Corporate Counsel for Gulf Power in 1992. He was named to his current position in May 2013. Previously, he was Executive Vice President, General Counsel, and Corporate Secretary of the Company, President and Chief Executive Officer of Savannah Electric and Power Company, and Vice President of Power Generation and Transmission at Gulf Power.

8. James Y. Kerr II
Executive Vice President and General Counsel
Kerr, 51, assumed his current role in March 2014. Previously, he was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC. He also served as co-chairman of the McGuireWoods energy industry team with focus in the areas of energy transactions and finance, energy regulation, energy policy, and energy litigation. Prior to joining McGuireWoods, Kerr served as a Commissioner on the North Carolina Utilities Commission and was the former President of the National Association of Regulatory Utility Commissioners.

9. Stephen E. Kuczynski

Chairman, President, and Chief Executive Officer of Southern Nuclear

Kuczynski, 52, joined the Company in July 2011 as President and Chief Executive Officer of Southern Nuclear. Previously, he served as Senior Vice President of Engineering and Technical Services of Exelon Nuclear. He also served as Senior Vice President of Exelon Nuclear's Midwest operations, Senior Vice President of Operations Support, and Plant Manager and later Site Vice President for Exelon's Byron Nuclear Station.

10. Mark S. Lantrip

Executive Vice President and Chairman, President, and Chief Executive Officer, Southern Company Services, Inc.

Lantrip, 60, joined the Company in 1981 as an analyst in Gulf Power's Corporate Planning department. He assumed his current position in March 2014. Previously, Lantrip was Executive Vice President of Finance and Treasurer of Southern Company Services, Inc. and Treasurer of the Company, with responsibility for financial planning and analysis, enterprise risk management, trust finance, capital markets, and treasury.

11. Christopher C. Womack

Executive Vice President and President of External Affairs

Womack, 57, joined the Company in 1988 as a Governmental Affairs Representative for Alabama Power. He has held his current position since January 2009. Previously, Womack was Executive Vice President of External Affairs for Georgia Power. He has also served as Senior Vice President of Human Resources and Chief People Officer for the Company, as well as Senior Vice President and Senior Production Officer of Southern Company Generation.

Biographical information for the Board of Directors is set forth on pages 1 through 8 of the attached Proxy Statement.

Transfer Agent

Computershare Inc. (Computershare) is Southern Company's transfer agent, dividend-paying agent, investment plan administrator, and registrar. If you have questions concerning your registered shareowner account, please contact:

By Mail

Computershare
P.O. Box 30170
College Station, TX 77842-3170

By Courier

Computershare
211 Quality Circle
Suite 210
College Station, TX 77845

By Phone-United States

9 a.m. to 7 p.m. ET
Monday through Friday
800-554-7626
(Automated voice response system 24 hours/day, 7 days/ week)
Hearing Impaired: 800-231-5469

By Phone-Outside United States

201-680-6693

Shareowner Services Internet Site

To take advantage of Computershare's online services, you will need to activate your account. This one-time authentication process will be used to validate your identity in addition to your 12-digit Investor ID and your Computershare Holder ID. The internet address is www.computershare.com/investor. Through this site, registered shareowners can securely access their account information, as well as submit numerous transactions. Also, transfer instructions and service request forms can be obtained.

Southern Investment Plan

The Southern Investment Plan provides a convenient way to purchase common stock and reinvest dividends. You can access the Southern Company internet site to review the prospectus.

Direct Registration

Southern Company common stock can be issued in direct registration (uncertificated) form. The stock is Direct Registration System eligible.

Dividend Payments

The entire amount of dividends paid in 2014 is taxable. The Board of Directors sets the record and payment dates for quarterly dividends. A dividend of 52.50 cents per share was paid in March 2015. For the remainder of 2015, projected record dates are May 18, August 17, and November 16. Projected payment dates for dividends declared during the remainder of 2015 are June 6, September 5, and December 5.

Auditors

Deloitte & Touche LLP
191 Peachtree St. NE
Suite 2000
Atlanta, GA 30303

During 2014, there were no changes in or disagreements with the auditors on accounting and financial disclosure.

Investor Information Line

For information about earnings and dividends, stock quotes, and current news releases, please visit investor.southerncompany.com.

Institutional Investor Inquiries

Southern Company maintains an investor relations office in Atlanta, 404-506-5310, to meet the information needs of institutional investors and securities analysts.

Electronic Delivery Of Proxy Materials

Any stockholder may enroll for electronic delivery of proxy materials at www.icsdelivery.com/so.

Environmental Information

Southern Company publishes a variety of information on its activities to meet the Company's environmental commitments. It is available online at www.southerncompany.com/planetpower/#reports.

To request printed materials, write to:

Larry Monroe
Chief Environmental Officer and Senior Vice President
Research and Environmental Affairs
600 North 18th St.
Bin 14N-8195
Birmingham, AL 35203-2206

Common Stock

Southern Company's common stock is listed on the New York Stock Exchange under the ticker symbol SO. On January 31, 2015, Southern Company had 136,875 stockholders of record.

Principal Executive Office

Southern Company's principal executive office is located at 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

SOUTHERN COMPANY

Recycled Paper Logo

Exhibit 8

SOUTHERN CO

FORM 10-K
(Annual Report)

Filed 03/02/15 for the Period Ending 12/31/14

Address	30 IVAN ALLEN JR. BLVD., N.W. ATLANTA, GA 30308
Telephone	4045065000
CIK	0000092122
Symbol	SO
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2014

OR

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

For the Transition Period from to

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

Atlanta, Georgia 30308
(404) 506-5000

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			**Georgia Power Company**
6 1/8% Series			
Senior Notes			**Gulf Power Company**
5.75% Series 2011A			
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value			**Mississippi Power Company**
5.25% Series			

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 ☒ (Response applicable to all registrants.)

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

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

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

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

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

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

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2014: $40.7 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2015
The Southern Company	Par Value $5 Per Share	909,877,898
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	5,642,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2015 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2015 Annual Meetings of Shareholders are incorporated by reference into PART III.

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

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

Table of Contents

DEFINITIONS

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

Term	Meaning
Alabama Power	Alabama Power Company
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
Clean Air Act	Clean Air Act Amendments of 1990
CCR	Coal combustion residuals
CO_2	Carbon dioxide
Code	Internal Revenue Code of 1986, as amended
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
Dalton	City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners
DOE	U.S. Department of Energy
Duke Energy Florida	Duke Energy Florida, Inc.
EPA	U.S. Environmental Protection Agency
EMC	Electric membership corporation
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MATS rule	Mercury and Air Toxics Standards rule
MEAG Power	Municipal Electric Authority of Georgia
Mississippi Power	Mississippi Power Company
MW	Megawatt
NRC	U.S. Nuclear Regulatory Commission
NYSE	New York Stock Exchange
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative
PPA	Power Purchase Agreement

DEFINITIONS
(continued)

Term	**Meaning**
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company
RUS	Rural Utilities Service
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
TIPA	Tax Increase Prevention Act of 2014
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the strategic goals for the wholesale business, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan , postretirement benefit plan , and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions and construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water , coal combustion residuals, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards , including any PSC requirements and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;

- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between Mississippi Power and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities, and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's or any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

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

PART I

Item 1. BUSINESS

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

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

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

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

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

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power Company is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, in the State of North Carolina on February 19, 2007, and in the State of South Carolina on March 31, 2009. Certain of Southern Power Company's subsidiaries are also admitted to do business in the States of California, Nevada, New Mexico, and Texas.

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

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 KWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

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

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

The Southern Company System

Traditional Operating Companies

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

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

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

Southern Company, each traditional operating company, Southern Power Company, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Southern Power Company and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power Company, which are subject to FERC regulations.

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

Southern Power

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

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

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

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

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

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

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

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

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

Southern Power's natural gas and biomass sales are primarily through long-term PPAs. Southern Power's natural gas PPAs consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable.

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

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

Block Sales PPAs

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

(1) North Carolina Electric Membership Corporation (NCEMC)

(2) North Carolina Municipal Power Agency (NCMPA)

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

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

(5) Pennsylvania, Jersey, Maryland Power Pool

Requirements Services PPAs

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

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

Solar PPAs

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

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

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

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

Purchased Power

Facility/Source	Counterparty	MWs	Contract Term
Sandersville	AL Sandersville Holdings, LLC	280	through December 2015
NCEMC	NCEMC	100	through December 2021

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

For the year ended December 31, 2014, Southern Power derived approximately 10.1% of its revenues from sales to Florida Power & Light Company, approximately 9.7% of its revenues from sales to Georgia Power, and approximately 9.1% of its revenues from sales to Duke Energy Corporation.

Other Businesses

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

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

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

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2015 through 2017, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental statutes and regulations. In 2015, the construction program is expected to be apportioned approximately as follows:

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

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

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

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

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

In addition, the construction program includes the development and construction of new generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC).

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4. Also see Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein for additional information regarding Mississippi Power's construction of the Kemper IGCC.

Financing Programs

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

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2012 through 2014.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2015. These agreements have terms ranging between one and six years. In 2014, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.96% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2014, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to help ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2015, SCS has contracted for 446 billion cubic feet of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

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

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

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. As of December 31, 2014, the territory had an area of approximately 120,000 square miles and an estimated population of approximately 16 million. Southern Power sells electricity at market-based rates in the wholesale market primarily to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

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

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

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

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

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

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of December 31, 2014, there were 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. As of December 31, 2014, PowerSouth owned generating units with approximately 2,094 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territories of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC.

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

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided. In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby Mississippi Power and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. In December 2013, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

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

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

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

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

As of December 31, 2014, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

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

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

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

Competition

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

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

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

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

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

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

As of December 31, 2014, Alabama Power had cogeneration contracts in effect with 10 industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2014, Alabama Power purchased approximately 172 million KWHs from such companies at a cost of $4.6 million.

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

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

As of December 31, 2014, Gulf Power had agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2014, Gulf Power purchased 185 million KWHs from such companies for approximately $8.1 million.

As of December 31, 2014, Mississippi Power had one cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2014, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

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

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

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

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2014, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 KWs and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 KWs.

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

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

In June 2013, the FERC entered an order granting Alabama Power's application for relicensing of Alabama Power's seven hydroelectric developments on the Coosa River for 30 years. In July 2013, Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. The Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission have also filed petitions for rehearing of the FERC order.

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

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

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

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

Licenses for all projects, excluding those discussed above, expire in the period 2023-2034 in the case of Alabama Power's projects and in the period 2020-2044 in the case of Georgia Power's projects.

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

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

Nuclear Regulation

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

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

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

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

Environmental Statutes and Regulations

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to the Southern Company system, including laws and regulations designed to address air quality, water, CCRs, global climate change, or other environmental and health concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including, but not limited to, the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act and proposed and final regulations related to air quality, water, greenhouse gases, and CCRs. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and climate change regulation.

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

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCRs, global climate change, or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

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

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

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

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

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

The traditional operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

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

Mississippi Power serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 21.9% of Mississippi Power's operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

Integrated Resource Planning

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

Certain of the traditional operating companies periodically file IRPs with their respective state PSC as discussed below.

Georgia Power

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

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters - Georgia Power - Rate Plans" and "– Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Integrated Resource Plans," "– Renewables Development," and "– Nuclear Construction" in Item 8 herein for additional information.

Gulf Power

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

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in November 2014. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals," and "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to evaluate the economics of various potential planning scenarios for units at certain Gulf Power coal-fired generating plants as EPA and other regulations develop.

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

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

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

Mississippi Power

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

Mississippi Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. In February 2015, the Mississippi Supreme Court declined to rule on the constitutionality of the Baseload Act.

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

For information regarding the February 2015 decision of the Mississippi Supreme Court related to the Baseload Act and the rates implemented in March 2013, see Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle – 2015 Mississippi Supreme Court Decision" and Note 3 to the financial statements of Mississippi Power under "Integrated Coal Gasification Combined Cycle - 2015 Mississippi Supreme Court Decision" in Item 8 herein.

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

Employee Relations

The Southern Company system had a total of 26,369 employees on its payroll at December 31, 2014.

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

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

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

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

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2016.

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

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. In 2013, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper IGCC, which is in effect through March 15, 2016.

Southern Nuclear has an agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2016. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

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

Item 1A. RISK FACTORS

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

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

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

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, physical security and cyber-security policies and practices, and the construction and operation of fossil-fuel, nuclear, hydroelectric, solar, wind, and biomass generating facilities, as well as transmission and distribution facilities. For example, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. The traditional operating companies seek to recover their costs (including a reasonable return on invested capital) through their retail rates, and there can be no assurance that a state PSC, in a future rate proceeding, will not alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Additionally, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's ability to conduct business pursuant to FERC market-based rate authority. The FERC rules related to retaining the authority to sell electricity at market-based rates in the wholesale markets are important for the traditional operating companies and Southern Power if they are to remain competitive in the wholesale markets in which they operate.

The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, water, CCR, global climate change, renewable energy standards, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, and/or Southern Power.

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

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

In addition, the EPA has published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions.

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

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations; the time periods over which compliance with regulations is required; individual state implementation of regulations, as applicable; the outcome of any legal challenges to the environmental rules and any additional rulemaking activities in response to legal challenges and court decisions; the cost, availability, and existing inventory of emissions allowances; the impact of future changes in generation and emissions-related technology and costs; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. Additionally, if Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines and/or remediation costs. The EPA has filed civil actions against Alabama Power and Georgia Power and issued notices of violation to Gulf Power and Mississippi Power alleging violations of the new source review provisions of the Clean Air Act. An adverse outcome in any of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties.

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

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

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

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

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

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations also impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control. The financial condition, net income, and cash flows of Southern Company, the traditional operating companies, and Southern Power could be adversely affected by these and other changes.

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

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

OPERATIONAL RISKS

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

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

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

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company. In addition, an investment in a subsidiary with such generation, transmission, or distribution facilities could be adversely impacted.

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

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 7.9%, of the Southern Company system's generation capacity as of December 31, 2014. In addition, these units generated approximately 23% and 22% of the total KWHs generated by Alabama Power and Georgia Power, respectively, in the year ended December 31, 2014. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

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

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

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

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

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

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

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

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

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

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

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

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

Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane or a pipeline failure. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas.

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

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

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made.

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

A key element of the business models of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. Advances in technology or changes in laws or regulations could reduce the cost of these or other alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation. Broader use of distributed generation by retail electric customers may also result from customers’ changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, there can be no assurance that a state PSC or legislature will not attempt to modify certain aspects of the traditional operating companies’ business as a result of these advances in technology. If these technologies became cost competitive and achieved sufficient scale, the market share of the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power. If state PSCs fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the traditional operating companies could be materially adversely affected.

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

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, especially with the workforce needs associated with the Kemper IGCC and Plant Vogtle Units 3 and 4 construction. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

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

General

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

- shortages and inconsistent quality of equipment, materials, and labor;
- labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction or other agreements or non-performance by other major participants in construction projects;

- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with licensing requirements;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

In addition, with respect to the construction of Plant Vogtle Units 3 and 4 and the operation of existing nuclear units, a major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company.

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

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

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the Kemper IGCC.

Plant Vogtle Units 3 and 4 construction

Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4 (each, an approximately 1,100 MW AP1000 nuclear generating unit). Georgia Power owns 45.7% of the new units. The NRC certified the Westinghouse Electric Company LLC's Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined COLs in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.

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

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Georgia Power's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by Georgia Power and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the Nuclear Construction Cost Recovery tariff.

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

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

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

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

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

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

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

Kemper IGCC construction

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

The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

Mississippi Power does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). Through December 31, 2014, Southern Company and Mississippi Power recorded pre-tax charges to income as a result of increases to the cost estimate of $2.05 billion ($1.26 billion after tax). Primarily as a result of these charges, Mississippi Power incurred net losses after dividends on preferred stock of $328.7 million and $476.6 million in the years ended December 31, 2014 and 2013, respectively. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's and Mississippi Power's statements of income and these changes could be material.

Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The 2013 Settlement Agreement also allowed Mississippi Power to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in February 2013. Mississippi Power's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan (described below) as approved by the Mississippi PSC.

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued a rate order (2013 MPSC Rate Order), approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

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

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

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

On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the collection of $156 million annually to be set aside in a regulatory liability account for use in mitigating future rate impacts for customers (Mirror CWIP) was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC

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

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

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

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

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

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

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

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

FINANCIAL, ECONOMIC, AND MARKET RISKS

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

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

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;

- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

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

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

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

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

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

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

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

Electric power supply is generally a seasonal business. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power may fluctuate substantially on a seasonal basis. In addition, the traditional operating companies and Southern Power have historically sold less power when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, and available cash of Southern Company, the traditional operating companies, and/or Southern Power.

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions which could be subject to major storm activity. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

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

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

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

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

Southern Company and its subsidiaries may face significant competition for acquisition opportunities and there can be no assurance that anticipated acquisitions will be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

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

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

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

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

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

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

Southern Company, the traditional operating companies, and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional operating companies may not be able to extend existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or they may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

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

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

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

Customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts, which could negatively impact the results of operations of Southern Company, the traditional operating companies, and Southern Power. In addition, a number of regulatory and legislative bodies have proposed or introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. For example, if any traditional operating company is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional operating company and Southern Company.

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

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

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

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

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

In addition, Georgia Power’s ability to make future borrowings through its term loan credit facility with the Federal Financing Bank is subject to the satisfaction of customary conditions, as well as certification of compliance with the requirements of the loan guarantee program under Title XVII of the Energy Policy Act of 2005, including accuracy of project-related representations and warranties, delivery of updated project-related information and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE’s consulting engineer that proceeds of the advances are used to reimburse certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program.

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

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

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

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, there is no guarantee that the insurance policies maintained by the Southern Company, the traditional operating companies, and Southern Power will cover all of the potential exposures or the actual amount of loss incurred.

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

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

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

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties

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

Generating Station	Location	Nameplate Capacity (1)	
		(KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	
Gorgas	Jasper, AL	1,221,250	(2)
Barry	Mobile, AL	1,525,000	(2)
Greene County	Demopolis, AL	300,000	(3)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(4)
Alabama Power Total		6,578,538	
Bowen	Cartersville, GA	3,160,000	
Branch	Milledgeville, GA	1,220,700	(5)
Hammond	Rome, GA	800,000	
Kraft	Port Wentworth, GA	281,136	(5)
McIntosh	Effingham County, GA	163,117	
McManus	Brunswick, GA	115,000	(5)
Mitchell	Albany, GA	125,000	(6)
Scherer	Macon, GA	750,924	(7)
Wansley	Carrollton, GA	925,550	(8)
Yates	Newnan, GA	1,250,000	(5)
Georgia Power Total		8,791,427	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(9)
Lansing Smith	Panama City, FL	305,000	(10)
Scholz	Chattahoochee, FL	80,000	(10)
Scherer Unit 3	Macon, GA	204,500	(7)
Gulf Power Total		2,059,500	
Daniel	Pascagoula, MS	500,000	(9)
Greene County	Demopolis, AL	200,000	(3)
Sweatt	Meridian, MS	80,000	(11)
Watson	Gulfport, MS	1,012,000	(11)
Mississippi Power Total		1,792,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(12)
Total Fossil Steam		20,221,465	

Generating Station	Location	Nameplate Capacity (1)	
IGCC			
Kemper County/Ratcliffe	Kemper County, MS	778,772	(13)
Total IGCC		778,772	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(14)
Vogtle Units 1 and 2	Augusta, GA	1,060,240	(15)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	19,700	(5)
Intercession City	Intercession City, FL	47,667	(16)
Kraft	Port Wentworth, GA	22,000	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Mitchell	Albany, GA	78,800	
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(8)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,907,489	
Lansing Smith Unit A	Panama City, FL	39,400	
Pea Ridge Units 1 through 3	Pea Ridge, FL	15,000	
Gulf Power Total		54,400	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(17)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Addison (formally West Georgia)	Thomaston, GA	668,800	
Cleveland County	Cleveland County, NC	720,000	
Dahlberg	Jackson County, GA	756,000	
Oleander	Cocoa, FL	791,301	
Rowan	Salisbury, NC	455,250	
Southern Power Total		3,391,351	
Gaston **(SEGCO)**	Wilsonville, AL	19,680	(12)
Total Combustion Turbines		6,318,972	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	
COMBINED CYCLE			
Barry	Mobile, AL		

Generating Station	Location	Nameplate Capacity (1)	
Alabama Power Total		1,070,424	
McIntosh Units 10&11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	
Georgia Power Total		3,838,920	
Smith	Lynn Haven, FL		
Gulf Power Total		545,500	
Daniel	Pascagoula, MS		
Mississippi Power Total		1,070,424	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(18)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,208,939	
Total Combined Cycle		11,734,207	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(19)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	
6 Other Plants	Various Georgia Cities	18,080	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	

Generating Station	Location	Nameplate Capacity (1)	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Dalton	Dalton, GA	7,769	
Georgia Power Total		7,769	
Adobe	Kern County, CA	20,000	
Apex	North Las Vegas, NV	20,000	
Campo Verde	Imperial County, CA	147,420	
Cimarron	Springer, NM	30,640	
Granville	Oxford, NC	2,500	
Imperial Valley	Imperial County, CA	163,200	
Macho Springs	Luna County, NM	55,000	
Spectrum	Clark County, NV	30,240	
Southern Power Total		469,000	(20)
Total Solar		476,769	
LANDFILL GAS FACILITY			
Perdido	Escambia County, FL		
Gulf Power Total		3,200	
BIOMASS FACILITY			
Nacogdoches	Sacul, TX		
Southern Power Total		115,500	
Total Generating Capacity		46,548,998	

Notes:

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

(2) As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7 (200MWs). Alabama Power also plans to cease using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and begin operating that unit solely on natural gas. These plans are expected to be effective no later than April 2016. See MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Alabama Power - Environmental Accounting Order" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Environmental Accounting Order" of Alabama Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Alabama Power under "Retail Regulatory Matters - Alabama Power - Environmental Accounting Order" and "Retail Regulatory Matters - Environmental Accounting Order," respectively, in Item 8 herein.

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

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

(5) See MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Georgia Power - Integrated Resource Plans" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS - FUTURE EARNINGS POTENTIAL - "Retail Regulatory Matters - Integrated Resource Plans" of Georgia Power in Item 7 herein. See also Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters - Georgia Power - Integrated Resource Plans" and "Retail Regulatory Matters - Integrated Resource Plans," respectively, in Item 8 herein for information on plant retirements, fuel switching, and conversions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(20) Southern Power total solar capacity shown is 100% of the nameplate capacity for each facility. When taking into consideration Southern Power's 90% equity interest in STR (which includes Adobe, Apex, Campo Verde, Cimarron, Granville, Macho Springs, and Spectrum) and 51% equity interest in SG2 Holdings (which includes Imperial Valley), Southern Power's equity portion of the total nameplate capacity is 358,452 KWs.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2014, the unamortized portion of this cost was approximately $13.7 million.

In conjunction with the Kemper IGCC, Mississippi Power owns a lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. The estimated capital cost of the mine and equipment is approximately $232.3 million, all of which has been incurred as of December 31, 2014. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2014, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 37,119,000 KWs and occurred on January 7, 2014. The all-time maximum demand of 38,777,000 KWs on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in 2014 was 20.2%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power at December 31, 2014 had undivided interests in certain generating plants and other related facilities with non-affiliated parties. The percentages of ownership of the total plant or facility are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Duke Energy Florida	Southern Power	OUC	FMPA	KUA
	(MWs)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	—%	—%	—%	—%	—%	—%	—%	—%	—%
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—	—
Intercession City, FL	143	—	—	33.3	—	—	—	66.7	—	—	—	—
Plant Stanton A	660	—	—	—	—	—	—	—	65.0	28.0	3.5	3.5

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

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments — Purchased Power Commitments" in Item 8 herein for additional information. Georgia Power is currently constructing Plant Vogtle Units 3 and 4 which will be jointly owned by Georgia Power, Dalton, OPC, and MEAG Power (with each owner holding the same undivided ownership interest as shown in the table above with respect to Plant Vogtle Units 1 and 2). In addition, Mississippi Power is constructing the Kemper IGCC and expects to sell a 15% ownership interest in the Kemper IGCC to SMEPA. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters - Georgia Power - Nuclear Construction" and "Retail Regulatory Matters - Nuclear Construction," respectively, in Item 8 herein. Also see Note 3 to the financial statements of each of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" in Item 8 herein for additional information.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the (1) liens pursuant to pollution control revenue bonds of Gulf Power on specific pollution control facilities, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, and (3) liens associated with Georgia Power’s reimbursement obligations to the DOE under its loan guarantee, which are secured by a first priority lien on (a) Georgia Power’s 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (b) Georgia Power’s rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Assets Subject to Lien", Note 6 to the financial statements of Southern Company and Georgia Power under “DOE Loan Guarantee Borrowings” and Note 6 of the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

Item 3. LEGAL PROCEEDINGS

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

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

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

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

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

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

(3) Environmental Remediation

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

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

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2014.

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

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

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

S. W. Connally, Jr.
President and Chief Executive Officer of Gulf Power
Age 45
Elected in 2012. President, Chief Executive Officer, and Director of Gulf Power since July 2012. Previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

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

Kimberly S. Greene
Executive Vice President
Age 48

Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene previously served at Tennessee Valley Authority in a number of positions, most recently as Executive Vice President and Chief Generation Officer from 2011 through April 2013, and Group President of Strategy and External Relations from 2010 through 2011.

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

James Y. Kerr II
Executive Vice President and General Counsel
Age 50
Elected in 2014. Before joining Southern Company, Mr. Kerr was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC from 2008 through February 2014.

Stephen E. Kuczynski
President and Chief Executive Officer of Southern Nuclear
Age 52
Elected in 2011. President and Chief Executive Officer of Southern Nuclear since July 2011. Before joining Southern Company, Mr. Kuczynski served at Exelon Corporation as the Senior Vice President of Engineering and Technical Services for Exelon Nuclear from February 2006 to June 2011.

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

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

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

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2014.

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

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

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

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

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 43
Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013 and Plant Manager of Georgia Power's Plant Wansley from March 2006 to July 2010.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on April 25, 2014 for one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2014.

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

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

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
Age 58
Elected in 2013. Executive Vice President, Chief Financial Officer, and Treasurer since March 2013. Also, served as Comptroller from March 2013 until January 2014. Previously served as Comptroller and Chief Accounting Officer of Southern Company, as well as Senior Vice President and Comptroller of SCS from March 2006 to March 2013.

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

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

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

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

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

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2014.

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

John W. Atherton
Vice President
Age 54
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012. Previously served as Vice President of External Affairs from January 2005 until October 2012.

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

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

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

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

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

Emile J. Troxclair, III
Vice President
Age 57
Elected in 2014. Vice President of Kemper Development since January 2015. Previously served as Vice President of Gasification for Lummus Technology Inc. from May 2013 through April 2014, Manager of E-Gas Technology for Phillips 66 from 2012 to May 2013, and Manager of E-Gas Technology for ConocoPhillips from 2003 to 2012.

The officers of Mississippi Power were elected for a term running from the meeting of the directors held on April 22, 2014 for one year or until their successors are elected and have qualified, except for Mr. Troxclair, whose election was effective on January 3, 2015.

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

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

PART II

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

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

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

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

(a)(2) Number of Southern Company's common stockholders of record at January 31, 2015: 136,875

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

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

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

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

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

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

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

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

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

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Item 7. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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

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

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

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

Earnings

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

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

Basic EPS was $2.19 in 2014, $1.88 in 2013, and $2.70 in 2012. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.18 in 2014, $1.87 in 2013, and $2.67 in 2012. EPS for 2014 was negatively impacted by $0.06 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.0825 in 2014 , $2.0125 in 2013 , and $1.9425 in 2012 . In January 2015 , Southern Company declared a quarterly dividend of 52.50 cents per share. This is the 269th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2014 , the actual dividend payout ratio was 95%, while the payout ratio of net income excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the 2015 Mississippi Supreme Court decision was 74%.

RESULTS OF OPERATIONS

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

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

Electricity Business

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

A condensed statement of income for the electricity business follows:

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

Electric Operating Revenues

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

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

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

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

See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters – Alabama Power – Rate CNP," " – Georgia Power – Rate Plans," and " – Gulf Power – Retail Base Rate Case" and "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

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

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs (other than solar PPAs) have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Wholesale revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale revenues from power sales were as follows:

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

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

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

Other Electric Revenues

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

Energy Sales

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

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

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

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 5.2 billion KWHs in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters

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

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

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

Fuel and Purchased Power Expenses

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

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

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

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

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

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

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

Fuel

In 2014, fuel expense was $6.0 billion , an increase of $495 million , or 9.0% , as compared to the prior year. The increase was primarily due to a 12.7% increase in the volume of KWHs generated by coal, a 10.3% increase in the average cost of natural gas per KWH generated, and a 30.7% decrease in the volume of KWHs generated by hydro facilities resulting from less rainfall, partially offset by a 5.0% decrease in the average cost of coal per KWH generated.

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

Purchased Power

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

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

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

Other Operations and Maintenance Expenses

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

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

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

Depreciation and Amortization

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

Depreciation and amortization increased $114 million , or 6.4% , in 2013 as compared to the prior year primarily due to additional plant in service related to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and six Southern Power plants between June 2012 and October 2013, certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service) at Georgia Power, and additional transmission and distribution projects. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" for additional information on Georgia Power's unit retirement decisions. These increases were partially offset by a net reduction in amortization primarily related to amortization of a regulatory liability for state income tax credits at Georgia Power and by the deferral of certain expenses under an accounting order at Alabama Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Compliance and Pension Cost Accounting Order" for additional information on Alabama Power's accounting order.

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

Taxes Other Than Income Taxes

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

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

Estimated Loss on Kemper IGCC

In 2014 and 2013, estimated probable losses on the Kemper IGCC of $868 million and $1.2 billion , respectively, were recorded at Southern Company. These losses reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). See FUTURE EARNINGS POTENTIAL – "Construction Program" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $55 million , or 28.9% , in 2014 as compared to the prior year primarily due to additional capital expenditures at the traditional operating companies, primarily related to environmental and transmission projects, as well as Mississippi Power's Kemper IGCC.

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

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

Interest Expense, Net of Amounts Capitalized

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

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

Other Income (Expense), Net

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

Income Taxes

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

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

Other Business Activities

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

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

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

Operating Revenues

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

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $27 million , or 39.7% , in 2014 as compared to the prior year. The increase was primarily due to insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC and higher operating expenses at Southern Holdings. Other operations and maintenance expenses for these other business activities decreased $9 million , or 11.7% , in 2013 as compared to the prior year. The decrease was primarily related to lower operating expenses at SouthernLINC Wireless and decreases in consulting and legal fees, partially offset by higher operating expenses at Southern Holdings and a decrease in the amount of insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC as compared to the amount received in 2012. See Note 3 to the financial statements under "Insurance Recovery" for additional information related to the litigation settlement with MC Asset Recovery, LLC.

Interest Income

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

Other Income (Expense), Net

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

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. See Note 1 under "Leveraged Leases" for additional information.

Interest Expense

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

Income Taxes

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

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4 as well as other ongoing construction projects. Other major factors include the profitability of the competitive wholesale business and successfully expanding investments in renewable energy projects. Future earnings for the electricity business in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, including the impact of ITCs, and the successful remarketing of capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the traditional operating companies and Southern Power, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

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

Environmental Statutes and Regulations

General

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014 , the traditional operating companies had invested approximately $10.6 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $1.1 billion, $0.7 billion, and $0.3 billion for 2014 , 2013 , and 2012 , respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $2.1 billion from 2015 through 2017 , with annual totals of approximately $1.0 billion , $0.5 billion , and $0.6 billion for 2015 , 2016 , and 2017 , respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order" and "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" herein and Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information on planned unit retirements and fuel conversions at Alabama Power, Georgia Power, and Mississippi Power.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Since 1990, the electric utilities have spent approximately $9.5 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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

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

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

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

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units. In March 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power believes this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units owned by Alabama Power, units co-owned with Mississippi Power, and units owned by SEGCO, which is jointly owned by Alabama Power and Georgia Power.

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

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

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

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

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama, Florida, Georgia, Mississippi, and North Carolina) to revise their SSM provisions within 18 months after issuance of the final rule.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, certain of the traditional operating companies have developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

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

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

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

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

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

Coal Combustion Residuals

The traditional operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 22 electric generating plants. In addition to on-site storage, the traditional operating companies also sell a portion of their CCR to third parties for beneficial reuse. Individual states regulate CCR and the states in the Southern Company system's service territory each have their own regulatory requirements. Each traditional operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

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

Environmental Remediation

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

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. Southern

Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2013 greenhouse gas emissions were approximately 102 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2014 greenhouse gas emissions on the same basis is approximately 112 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

Alabama Power

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

Rate RSE

Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If Alabama Power's actual retail return is above the allowed weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.

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

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 4, 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015.

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

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

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

Environmental Accounting Order

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

As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. Alabama Power also plans to cease using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

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

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, Alabama Power fully amortized the balance of $123 million in certain regulatory asset accounts, and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset account balances amortized as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, which were approved by the Alabama PSC in 2012 and August 2013, respectively. Approximately $95 million of non-nuclear outage costs and $28 million of compliance and pension costs were fully amortized at December 31, 2014.

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

Non-Environmental Federal Mandated Costs Accounting Order

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

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

Georgia Power

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

Rate Plans

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

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

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

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

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

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

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2014, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," "– Coal Combustion Residuals," and "– Global Climate Issues," and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2; the State of Georgia's Multi-Pollutant Rule; and Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

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

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

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

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

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

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances. On January 20, 2015, the Georgia PSC approved the deferral of Georgia Power's next fuel case filing until at least June 30, 2015.

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

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approval in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $6.7 billion , $5.4 billion , and $4.3 billion for 2015 , 2016 , and 2017 , respectively.

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

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

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

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

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

See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information.

Income Tax Matters

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

Bonus Depreciation

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

Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code of 1986, as amended (Internal Revenue Code) Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Through December 31, 2014 , Southern Company had recorded tax benefits totaling $276 million for the Phase II credits, of which approximately $210 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. Mississippi Power currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC.

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

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

Section 174 Research and Experimental Deduction

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

Other Matters

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

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 94% of Southern Company's total operating revenues for 2014 , are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs, including a reasonable return on equity. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

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

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

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

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

N/A – Not applicable

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

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

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

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Mississippi Power's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, w hich includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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

Recently Issued Accounting Standards

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2014 and 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2014 and December 31, 2013. Through December 31, 2014 , Southern Company has incurred non-recoverable cash expenditures of $1.3 billion and is expected to incur approximately $702 million in additional non-recoverable cash expenditures through completion of the Kemper IGCC. Southern Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2015 through 2017 , Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Southern Company system's projected capital expenditures in that period include investments to build new generation facilities, to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2014 as compared to December 31, 2013 . In December 2014, certain of the traditional operating companies and other subsidiaries voluntarily contributed an aggregate of $500 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015 . See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities in 2014 totaled $5.8 billion , a decrease of $282 million from 2013 . Significant changes in operating cash flow for 2014 as compared to 2013 include $500 million of voluntary contributions to the qualified pension plan and an increase in receivables due to under recovered fuel costs, partially offset by an increase in accrued compensation. Net cash provided from operating activities in 2013 totaled $6.1 billion , an increase of $1.2 billion from 2012 . The most significant change in operating cash flow for 2013 as compared to 2012 was a decrease in fossil fuel stock due to an increase in KWH generation.

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

Net cash provided from financing activities totaled $644 million in 2014 due to issuances of long-term debt and common stock, partially offset by common stock dividend payments, redemptions of long-term debt, and a reduction in short-term debt. Net cash used for financing activities totaled $324 million in 2013 due to redemptions of long-term debt and payments of common stock dividends, partially offset by issuances of long-term debt and common stock and an increase in notes payable. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

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

At the end of 2014 , the market price of Southern Company's common stock was $49.11 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $21.98 per share, representing a market-to-book value ratio of 223 %, compared to $41.11, $21.43, and 192%, respectively, at the end of 2013 .

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flow, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2015 , as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements.

Except as described herein, the traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from operating cash flows, external security issuances, term loans, short-term borrowings, and equity contributions or loans from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

On February 20, 2014, Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the FFB. Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and also are secured by a first priority lien on (i) Georgia Power's 45.7% ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, Georgia Power may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit

Facility will be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion . See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Eligible Project Costs incurred through December 31, 2014 would allow for borrowings of up to $2.1 billion under the FFB Credit Facility. Through December 31, 2014 , Georgia Power had borrowed $1.2 billion under the FFB Credit Facility, leaving $0.9 billion of currently available borrowing ability.

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the commercial operation of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2014, Southern Company's current liabilities exceeded current assets by $2.6 billion , primarily due to long-term debt of the traditional operating companies and Southern Power that is due within one year of $3.3 billion . To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets and financial institutions.

At December 31, 2014 , Southern Company and its subsidiaries had approximately $710 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2015	2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
					(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	228	50	—	1,030	1,308	1,308	58	—	58	170
Georgia Power	—	150	—	1,600	1,750	1,736	—	—	—	—
Gulf Power	80	165	30	—	275	275	50	—	50	30
Mississippi Power	135	165	—	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	488	—	—	—	—
Other	70	—	—	—	70	70	20	—	20	50
Total	$ 513	$ 530	$ 30	$ 4,130	$ 5,203	$ 5,177	$ 153	$ 40	$ 193	$ 320

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $1.8 billion . In addition, at December 31, 2014 , the traditional operating companies had $476 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain

pollution control revenue bonds of Georgia Power were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew their bank credit arrangements as needed, prior to expiration.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014:					
Commercial paper	**$ 803**	**0.3%**	**$ 754**	**0.2%**	**$ 1,582**
Short-term bank debt	**—**	**—%**	**98**	**0.8%**	**400**
Total	**$ 803**	**0.3%**	**$ 852**	**0.3%**	
December 31, 2013:					
Commercial paper	$ 1,082	0.2%	$ 993	0.3%	$ 1,616
Short-term bank debt	400	0.9%	107	0.9%	400
Total	$ 1,482	0.4%	$ 1,100	0.3%	
December 31, 2012:					
Commercial paper	$ 820	0.3%	$ 550	0.3%	$ 938
Short-term bank debt	—	—%	116	1.2%	300
Total	$ 820	0.3%	$ 666	0.5%	

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014 , 2013 , and 2012 .

The Company believes the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, bank notes, and cash from operations.

Financing Activities

During 2014 , Southern Company issued approximately 20.8 million shares of common stock (including approximately 5.0 million treasury shares) for approximately $806 million through the employee and director stock plans and the Southern Investment Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

From August 2013 through December 2014, Southern Company used shares held in treasury, to the extent available, and newly issued shares to satisfy the requirements under the Southern Investment Plan and the employee savings plan. Beginning in January 2015, Southern Company ceased issuing additional shares under the Southern Investment Plan and the employee savings plan. All sales under these plans are now being funded with shares acquired on the open market by the independent plan administrators.

Beginning in 2015, Southern Company expects to repurchase shares of common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises. The Southern Company Board of Directors has approved the repurchase of up to 20 million shares of common stock for such purpose until December 31, 2017. Repurchases may be made by means of open market purchases, privately negotiated transactions, or accelerated or other share repurchase programs, in accordance with applicable securities laws.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2014:

Company	Senior Note Issuances	Senior Note Maturities	Revenue Bond Issuances and Remarketings of Purchased Bonds [(a)]	Revenue Bond Redemptions	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions [(b)] and Maturities
	(in millions)					
Southern Company	$ 750	$ 350	$ —	$ —	$ —	$ —
Alabama Power	400	—	254	254	—	—
Georgia Power	—	—	40	37	1,200	5
Gulf Power	200	75	42	29	—	—
Mississippi Power	—	—	—	—	493	256
Southern Power	—	—	—	—	10	10
Other	—	—	—	—	—	19
Elimination [(c)]	—	—	—	—	(220)	(220)
Total	$ 1,350	$ 425	$ 336	$ 320	$ 1,483	$ 70

(a) Includes remarketing by Gulf Power of $13 million aggregate principal amount of revenue bonds previously purchased and held by Gulf Power since December 2013 and remarketing by Georgia Power of $40 million aggregate principal amount of revenue bonds previously purchased and held by Georgia Power since 2010.

(b) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(c) Intercompany loan from Southern Company to Mississippi Power eliminated in Southern Company's Consolidated Financial Statements. This loan was repaid on September 29, 2014.

In May 2014, Southern Company's $350 million aggregate principal amount of its Series 2009A 4.15% Senior Notes due May 15, 2014 matured.

In August 2014, Southern Company issued $400 million aggregate principal amount of Series 2014A 1.30% Senior Notes due August 15, 2017 and $350 million aggregate principal amount of Series 2014B 2.15% Senior Notes due September 1, 2019. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their respective continuous construction programs.

In addition to the amounts reflected in the table above, in June 2014, Southern Company entered into a 90 -day floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the investment by Southern Company in its subsidiaries. This bank loan was repaid in August 2014.

In addition to the amounts reflected in the table above, in January 2014 and October 2014, Mississippi Power received an additional $75 million and $50 million , respectively, of interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Proposed Sale of Undivided Interest to SMEPA" for additional information.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion on February 20, 2014 and $200 million on December 11, 2014. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029 and is expected to be reset from time to time thereafter through 2044. The interest rate applicable to the $200 million advance in

December 2014 is 3.002% for an interest period that extends to 2044. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the borrowings in 2014 under the FFB Credit Facility were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million , which are being amortized over the life of the borrowings under the FFB Credit Facility.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of Georgia Power or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

In February 2014, Georgia Power repaid three four -month floating rate bank loans in an aggregate principal amount of $400 million .

During 2014, Alabama Power entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

In October 2014, Georgia Power entered into interest rate swaps to hedge exposure to interest rate changes related to existing debt. The notional amount of the swaps totaled $900 million.

In November and December 2014, Georgia Power entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated borrowings under the FFB Credit Facility in 2015. The notional amount of the swaps totaled $700 million.

Subsequent to December 31, 2014, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035, which will occur on March 16, 2015.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, interest rate derivatives, and construction of new generation at Plant Vogtle Units 3 and 4.

The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	435
Below BBB- and/or Baa3	2,305

Subsequent to December 31, 2014, Moody's affirmed the senior unsecured debt rating of Mississippi Power and revised the ratings outlook for Mississippi Power from stable to negative.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2014 have a notional amount of $2.1 billion and are related to fixed and floating rate obligations. The weighted average interest rate on $3.4 billion of long-term variable interest rate exposure at January 1, 2015 was 0.94%. If Southern Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $34 million at January 1, 2015 . See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013 .

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (32)**	$ (85)
Contracts realized or settled:		
Swaps realized or settled	**(9)**	43
Options realized or settled	**6**	19
Current period changes [(a)] :		
Swaps	**(131)**	2
Options	**(22)**	(11)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (188)**	$ (32)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**200**	216
Commodity – Natural gas options	**44**	59
Total hedge volume	**244**	275

The weighted average swap contract cost above market prices was approximately $0.84 per mmBtu as of December 31, 2014 and $0.10 per mmBtu as of December 31, 2013 . The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, 2014 and 2013 , substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(188)	(109)	(76)	(3)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (188)	$ (109)	$ (76)	$ (3)

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Southern Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international, and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to be $6.7 billion for 2015 , $5.4 billion for 2016 , and $4.3 billion for 2017 , which includes expenditures related to the construction and start-up of the Kemper IGCC of $801 million for 2015 and $132 million for 2016. The amounts related to the construction and start-up of the Kemper IGCC exclude

SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC for approximately $596 million (including construction costs for all prior periods relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $1.0 billion , $0.5 billion , and $0.6 billion for 2015 , 2016 , and 2017 , respectively. The Southern Company system's amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for information regarding additional factors that may impact construction expenditures.

In addition, the construction program includes the development and construction of new generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC).

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt [a] —					
Principal	$ 3,302	$ 3,345	$ 2,050	$ 15,282	$ 23,979
Interest	857	1,563	1,355	11,379	15,154
Preferred and preference stock dividends [b]	68	136	136	—	340
Financial derivative obligations [c]	138	76	3	—	217
Operating leases [d]	100	154	73	248	575
Capital leases [d]	31	25	22	81	159
Unrecognized tax benefits [e]	170	—	—	—	170
Purchase commitments —					
Capital [f]	6,222	8,899	—	—	15,121
Fuel [g]	4,012	5,155	3,321	9,869	22,357
Purchased power [h]	327	738	761	3,892	5,718
Other [i]	233	476	378	1,369	2,456
Trusts —					
Nuclear decommissioning [j]	5	11	11	110	137
Pension and other postretirement benefit plans [k]	112	224	—	—	336
Total	$ 15,577	$ 20,802	$ 8,110	$ 42,230	$ 86,719

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015 , as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Represents preferred and preference stock of subsidiaries. Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and included in purchased power.

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2014 , significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(g) Primarily includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014 .

(h) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.1 billion of biomass PPAs is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Renewables Development" for additional information.

(i) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(j) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP for Georgia Power. Alabama Power also has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

(k) The Southern Company system forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from corporate assets of Southern Company's subsidiaries. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from corporate assets of Southern Company's subsidiaries.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the strategic goals for the wholesale business, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan , postretirement benefit plan , and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions and construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water , CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards , including any PSC requirements and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;

- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between Mississippi Power and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's or any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general , as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by Southern Company from time to time with the SEC.

Southern Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	$ **15,550**	$ 14,541	$ 14,187
Wholesale revenues	**2,184**	1,855	1,675
Other electric revenues	**672**	639	616
Other revenues	**61**	52	59
Total operating revenues	**18,467**	17,087	16,537
Operating Expenses:			
Fuel	**6,005**	5,510	5,057
Purchased power	**672**	461	544
Other operations and maintenance	**4,354**	3,846	3,772
Depreciation and amortization	**1,945**	1,901	1,787
Taxes other than income taxes	**981**	934	914
Estimated loss on Kemper IGCC	**868**	1,180	—
Total operating expenses	**14,825**	13,832	12,074
Operating Income	**3,642**	3,255	4,463
Other Income and (Expense):			
Allowance for equity funds used during construction	**245**	190	143
Interest income	**19**	19	40
Interest expense, net of amounts capitalized	**(835)**	(824)	(859)
Other income (expense), net	**(63)**	(81)	(38)
Total other income and (expense)	**(634)**	(696)	(714)
Earnings Before Income Taxes	**3,008**	2,559	3,749
Income taxes	**977**	849	1,334
Consolidated Net Income	**2,031**	1,710	2,415
Dividends on Preferred and Preference Stock of Subsidiaries	**68**	66	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	$ **1,963**	$ 1,644	$ 2,350
Common Stock Data:			
Earnings per share (EPS) —			
Basic EPS	$ **2.19**	$ 1.88	$ 2.70
Diluted EPS	**2.18**	1.87	2.67
Average number of shares of common stock outstanding — (in millions)			
Basic	**897**	877	871
Diluted	**901**	881	879

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
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	2014	2013	2012
		(in millions)	
Consolidated Net Income	**$ 2,031**	$ 1,710	$ 2,415
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(6), $-, and $(7), respectively	**(10)**	—	(12)
Reclassification adjustment for amounts included in net income, net of tax of $3, $5, and $7, respectively	**5**	9	11
Marketable securities:			
Change in fair value, net of tax of $-, $(2), and $-, respectively	**—**	(3)	—
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(32), $22, and $(2), respectively	**(51)**	36	(3)
Reclassification adjustment for amounts included in net income, net of tax of $2, $4, and $(4), respectively	**3**	6	(8)
Total other comprehensive income (loss)	**(53)**	48	(12)
Dividends on preferred and preference stock of subsidiaries	**(68)**	(66)	(65)
Consolidated Comprehensive Income	**$ 1,910**	$ 1,692	$ 2,338

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014 , 2013 , and 2012
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Activities:			
Consolidated net income	$ 2,031	$ 1,710	$ 2,415
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,293	2,298	2,145
Deferred income taxes	709	496	1,096
Investment tax credits	35	302	128
Allowance for equity funds used during construction	(245)	(190)	(143)
Pension, postretirement, and other employee benefits	(515)	131	(398)
Stock based compensation expense	63	59	55
Estimated loss on Kemper IGCC	868	1,180	—
Other, net	(38)	(41)	51
Changes in certain current assets and liabilities —			
-Receivables	(352)	(153)	234
-Fossil fuel stock	408	481	(452)
-Materials and supplies	(67)	36	(97)
-Other current assets	(57)	(11)	(37)
-Accounts payable	267	72	(89)
-Accrued taxes	(105)	(85)	(71)
-Accrued compensation	255	(138)	(28)
-Mirror CWIP	180	—	—
-Other current liabilities	85	(50)	89
Net cash provided from operating activities	5,815	6,097	4,898
Investing Activities:			
Property additions	(5,977)	(5,463)	(4,809)
Investment in restricted cash	(11)	(149)	(280)
Distribution of restricted cash	57	96	284
Nuclear decommissioning trust fund purchases	(916)	(986)	(1,046)
Nuclear decommissioning trust fund sales	914	984	1,043
Cost of removal, net of salvage	(170)	(131)	(149)
Change in construction payables, net	(107)	(126)	(84)
Prepaid long-term service agreement	(181)	(91)	(146)
Other investing activities	(17)	124	19
Net cash used for investing activities	(6,408)	(5,742)	(5,168)
Financing Activities:			
Increase (decrease) in notes payable, net	(676)	662	(30)
Proceeds —			
Long-term debt issuances	3,169	2,938	4,404
Interest-bearing refundable deposit	125	—	150
Preference stock	—	50	—
Common stock issuances	806	695	397
Redemptions and repurchases —			
Long-term debt	(816)	(2,830)	(3,169)
Common stock repurchased	(5)	(20)	(430)
Payment of common stock dividends	(1,866)	(1,762)	(1,693)
Payment of dividends on preferred and preference stock of subsidiaries	(68)	(66)	(65)
Other financing activities	(25)	9	19

Net cash provided from (used for) financing activities	**644**	(324)	(417)
Net Change in Cash and Cash Equivalents	**51**	31	(687)
Cash and Cash Equivalents at Beginning of Year	**659**	628	1,315
Cash and Cash Equivalents at End of Year	**$ 710**	$ 659	$ 628

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

Assets	2014	2013
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 710**	$ 659
Receivables —		
Customer accounts receivable	**1,090**	1,027
Unbilled revenues	**432**	448
Under recovered regulatory clause revenues	**136**	58
Other accounts and notes receivable	**307**	304
Accumulated provision for uncollectible accounts	**(18)**	(18)
Fossil fuel stock, at average cost	**930**	1,339
Materials and supplies, at average cost	**1,039**	959
Vacation pay	**177**	171
Prepaid expenses	**665**	278
Deferred income taxes, current	**506**	143
Other regulatory assets, current	**346**	207
Other current assets	**50**	39
Total current assets	**6,370**	5,614
Property, Plant, and Equipment:		
In service	**70,013**	66,021
Less accumulated depreciation	**24,059**	23,059
Plant in service, net of depreciation	**45,954**	42,962
Other utility plant, net	**211**	240
Nuclear fuel, at amortized cost	**911**	855
Construction work in progress	**7,792**	7,151
Total property, plant, and equipment	**54,868**	51,208
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,546**	1,465
Leveraged leases	**743**	665
Miscellaneous property and investments	**203**	218
Total other property and investments	**2,492**	2,348
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,510**	1,436
Prepaid pension costs	**—**	419
Unamortized debt issuance expense	**202**	139
Unamortized loss on reacquired debt	**243**	269
Other regulatory assets, deferred	**4,334**	2,495
Other deferred charges and assets	**904**	618
Total deferred charges and other assets	**7,193**	5,376
Total Assets	**$ 70,923**	$ 64,546

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
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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
At December 31, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

		2014	2013	2014	2013
			(in millions)		*(percent of total)*
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (3.36% at 1/1/15) due 2042		**$ 206**	$ 206		
Total long-term debt payable to affiliated trusts		**206**	206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2014	3.25% to 4.90%	**—**	428		
2015	0.55% to 5.25%	**2,375**	2,375		
2016	1.95% to 5.30%	**1,360**	1,360		
2017	1.30% to 5.90%	**1,495**	1,095		
2018	2.20% to 5.40%	**850**	850		
2019	2.15% to 5.55%	**1,175**	825		
2020 through 2051	1.63% to 6.38%	**10,574**	9,973		
Variable rate (1.29% at 1/1/14) due 2014		**—**	11		
Variable rates (0.77% to 1.17% at 1/1/15) due 2015		**775**	525		
Variable rates (0.56% to 0.63% at 1/1/15) due 2016		**450**	450		
Total long-term senior notes and debt		**19,054**	17,892		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	**25**	25		
2022 through 2049	0.28% to 6.00%	**1,466**	1,453		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015		**152**	54		
Variable rate (0.04% at 1/1/15) due 2016		**4**	4		
Variable rate (0.04% to 0.06% at 1/1/15) due 2017		**36**	36		
Variable rate (0.04% at 1/1/14) due 2018		**—**	19		
Variable rates (0.01% to 0.09% at 1/1/15) due 2020 to 2052		**1,566**	1,642		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
FFB loans (3.00% to 3.86%) due 2044		**1,200**	—		
Total other long-term debt		**4,719**	3,503		
Capitalized lease obligations		**159**	163		
Unamortized debt premium		**69**	79		
Unamortized debt discount		**(33)**	(30)		
Total long-term debt (annual interest requirement — $857 million)		**24,174**	21,813		
Less amount due within one year		**3,333**	469		
Long-term debt excluding amount due within one year		**20,841**	21,344	**49.4%**	51.5%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2014 and 2013
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	**2014**	2013
		(in millions)		*(percent of total)*
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	**81**	81		
$1 par value — 5.20% to 5.83%				
Authorized — 28 million shares				
Outstanding — 12 million shares: $25 stated value	**294**	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $20 million)	**375**	375	**0.9**	0.9
Redeemable Noncontrolling Interest	**39**	—	**0.1**	—
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,539**	4,461		
Authorized — 1.5 billion shares				
Issued — 2014: 909 million shares				
— 2013: 893 million shares				
Treasury — 2014: 0.7 million shares				
— 2013: 5.7 million shares				
Paid-in capital	**5,955**	5,362		
Treasury, at cost	**(26)**	(250)		
Retained earnings	**9,609**	9,510		
Accumulated other comprehensive loss	**(128)**	(75)		
Total common stockholders' equity	**19,949**	19,008	**47.3**	45.8
Preferred and Preference Stock of Subsidiaries and Noncontrolling Interest:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	**45**	45		
Preference stock				
Authorized — 65 million shares				
Outstanding — $1 par value	**343**	343		
— 5.63% to 6.50% — 14 million shares (non-cumulative)				
Outstanding — $100 par or stated value	**368**	368		
— 5.60% to 6.50% — 4 million shares (non-cumulative)				
Noncontrolling Interest	**221**	—		
Total preferred and preference stock of subsidiaries and noncontrolling interest (annual dividend requirement — $48 million)	**977**	756	**2.3**	1.8
Total stockholders' equity	**20,926**	19,764		
Total Capitalization	**$ 42,181**	$ 41,483	**100.0%**	100.0%

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2014 , 2013 , and 2012
Southern Company and Subsidiary Companies 2014 Annual Report

	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock							
	Issued	**Treasury**	**Par Value**	**Paid-In Capital**	**Treasury**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Preferred and Preference Stock of Subsidiaries**	**Noncontrolling Interest**	**Total**
	(in thousands)		*(in millions)*							
Balance at December 31, 2011	865,664	(539)	$4,328	$ 4,410	$ (17)	$ 8,968	$ (111)	$ 707	$ —	$ 18,285
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,350	—	—	—	2,350
Other comprehensive income (loss)	—	—	—	—	—	—	(12)	—	—	(12)
Stock issued	12,139	—	61	336	—	—	—	—	—	397
Stock repurchased, at cost	—	(9,440)	—	—	(430)	—	—	—	—	(430)
Stock-based compensation	—	—	—	106	—	—	—	—	—	106
Cash dividends of $1.9425 per share	—	—	—	—	—	(1,693)	—	—	—	(1,693)
Other	—	(56)	—	3	(3)	1	—	—	—	1
Balance at December 31, 2012	877,803	(10,035)	4,389	4,855	(450)	9,626	(123)	707	—	19,004
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,644	—	—	—	1,644
Other comprehensive income (loss)	—	—	—	—	—	—	48	—	—	48
Stock issued	14,930	4,443	72	441	203	—	—	49	—	765
Stock-based compensation	—	—	—	65	—	—	—	—	—	65
Cash dividends of $2.0125 per share	—	—	—	—	—	(1,762)	—	—	—	(1,762)
Other	—	(55)	—	1	(3)	2	—	—	—	—
Balance at December 31, 2013	**892,733**	**(5,647)**	**4,461**	**5,362**	**(250)**	**9,510**	**(75)**	**756**	**—**	**19,764**
Net income after dividends on preferred and preference stock of subsidiaries	**—**	**—**	**—**	**—**	**—**	**1,963**	**—**	**—**	**—**	**1,963**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(53)**	**—**	**—**	**(53)**
Stock issued	**15,769**	**4,996**	**78**	**501**	**227**	**—**	**—**	**—**	**—**	**806**
Stock-based compensation	**—**	**—**	**—**	**86**	**—**	**—**	**—**	**—**	**—**	**86**
Cash dividends of $2.0825 per share	**—**	**—**	**—**	**—**	**—**	**(1,866)**	**—**	**—**	**—**	**(1,866)**
Contributions from noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**221**	**221**
Net income attributable to noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(2)**	**(2)**
Other	**—**	**(74)**	**—**	**6**	**(3)**	**2**	**—**	**—**	**2**	**7**
Balance at December 31, 2014	**908,502**	**(725)**	**$4,539**	**$ 5,955**	**$ (26)**	**$ 9,609**	**$ (128)**	**$ 756**	**$ 221**	**$ 20,926**

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2014 Annual Report

Index to the Notes to Financial Statements

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

Acquisitions entered into or made by Southern Power during 2014 and 2013 are detailed in the table below:

	MW Capacity	Percentage Ownership	Year of Operation	Party Under PPA Contract for Plant Output	PPA Contract Period	Purchase Price
						(millions)
SG2 Imperial Valley, LLC [(a)]	150	51%	2014	San Diego Gas & Electric Company	25 years	$504.7 [(c)]
Macho Springs Solar LLC [(b)]	50	90	2014	El Paso Electric Company	20 years	$130.0 [(d)]
Adobe Solar, LLC [(b)]	20	90	2014	Southern California Edison Company	20 years	$96.2 [(d)]
Campo Verde Solar, LLC [(b)(e)]	139	90	2013	San Diego Gas & Electric Company	20 years	$136.6 [(d)]

(a) This acquisition was made by Southern Power through its subsidiaries Southern Renewable Partnerships, LLC and SG2 Holdings, LLC. SG2 Holdings, LLC is jointly-owned by Southern Power and First Solar, Inc.

(b) This acquisition was made by Southern Power and Turner Renewable Energy, LLC through Southern Turner Renewable Energy, LLC.

(c) Reflects Southern Power's portion of the purchase price.

(d) Reflects 100% of the purchase price, including Turner Renewable Energy, LLC's 10% equity contribution.

(e) Under an engineering, procurement, and construction agreement, an additional $355.5 million was paid to a subsidiary of First Solar, Inc. to complete the construction of the solar facility.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.1% in 2014 , 3.3% in 2013 , and 3.2% in 2012 . Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $23.5 billion and $22.5 billion at December 31, 2014 and 2013 , respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Certain of Southern Power's generation assets are now depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. Cost, net of salvage value, of these assets is depreciated on an hours or starts units-of-production basis. The book value of plant-in-service as of December 31, 2014 that is depreciated on a units-of-production basis was approximately $470.2 million .

In 2009, the Georgia PSC approved an accounting order allowing Georgia Power to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of Georgia Power's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), Georgia Power amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $14 million is being amortized annually by Georgia Power over the three years ending December 31, 2016. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years . Accumulated depreciation for other plant in service totaled $533 million and $513 million at December 31, 2014 and 2013 , respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Southern Company system's nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Southern Company system has retirement obligations related to various landfill sites, ash ponds, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

	2014	2013
	(in millions)	
Balance at beginning of year	**$ 2,018**	$ 1,757
Liabilities incurred	**18**	6
Liabilities settled	**(17)**	(16)
Accretion	**102**	97
Cash flow revisions	**80**	174
Balance at end of year	**$ 2,201**	$ 2,018

The cash flow revisions in 2014 are primarily related to Alabama Power's and SEGCO's AROs associated with asbestos at their steam generation facilities. The cash flow revisions in 2013 are primarily related to revisions to the nuclear decommissioning ARO based on Alabama Power's updated decommissioning study and Georgia Power's updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the traditional operating companies' ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, Southern Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $860 million and ongoing post-closure care of approximately $140 million . Certain of the traditional operating companies have previously recorded AROs associated with ash ponds of $506 million , or $468 million on a nominal dollar basis, based on existing state requirements. During 2015, the traditional operating companies will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Southern Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2014 and 2013 , approximately $51 million and $32 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $52 million and $33 million at December 31, 2014 and 2013 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2014 , investment securities in the Funds totaled $1.5 billion , consisting of equity securities of $886 million , debt securities of $638 million , and $19 million of other securities. At December 31, 2013 , investment securities in the Funds totaled $1.5 billion , consisting of equity securities of $896 million , debt securities of $528 million , and $40 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $913 million , $1.0 billion , and $1.0 billion in 2014 , 2013 , and 2012 , respectively, all of which were reinvested. For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $98 million , of which $2 million related to realized gains and $19 million related to unrealized gains and losses related to securities held in the Funds at December 31, 2014 . For 2013 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $181 million , of which $5 million related to realized gains and $119 million related to unrealized gains related to securities held in the Funds at December 31, 2013 . For 2012 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $137 million , of which $4 million related to realized gains and $75 million related to unrealized gains related to securities held in the Funds at December 31, 2012 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2014 and 2013 , the accumulated provisions for decommissioning were as follows:

	External Trust Funds		Internal Reserves		Total	
	2014	2013	**2014**	2013	**2014**	2013
			(in millions)			
Plant Farley	**$ 754**	$ 713	**$ 21**	$ 21	**$ 775**	$ 734
Plant Hatch	**496**	469	**—**	—	**496**	469
Plant Vogtle Units 1 and 2	**293**	277	**—**	—	**293**	277

NOTES (continued)
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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 .

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 i n 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)

NOTES (continued)
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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

NOTES (continued)
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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**

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in millions)	
Service cost	$ 213	$ 232	$ 198
Interest cost	435	389	393
Expected return on plan assets	(645)	(603)	(581)
Recognized net loss	110	200	95
Net amortization	26	27	30
Net periodic pension cost	$ 139	$ 245	$ 135

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2014 , estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2015	$ 522
2016	450
2017	478
2018	499
2019	524
2020 to 2024	2,962

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,682	$ 1,872
Service cost	21	24
Interest cost	79	74
Benefits paid	(102)	(94)
Actuarial (gain) loss	300	(200)
Plan amendments	(2)	—
Retiree drug subsidy	8	6
Balance at end of year	1,986	1,682
Change in plan assets		
Fair value of plan assets at beginning of year	901	821
Actual return on plan assets	54	129
Employer contributions	39	39
Benefits paid	(94)	(88)
Fair value of plan assets at end of year	900	901
Accrued liability	$ (1,086)	$ (781)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in millions)	
Other regulatory assets, deferred	$ 387	$ 109
Other current liabilities	(4)	(4)
Employee benefit obligations	(1,082)	(777)
Other regulatory liabilities, deferred	(21)	(36)
Accumulated OCI	8	1

NOTES (continued)
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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)
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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)
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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	42%	**41%**	40%
International equity	21	**23**	25
Domestic fixed income	24	**26**	24
Global fixed income	4	**3**	4
Special situations	1	**—**	—
Real estate investments	5	**5**	5
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2014 and 2013 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

NOTES (continued)
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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.

NOTES (continued)
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	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:				
Domestic equity*	$ 1,433	$ 839	$ —	$ 2,272
International equity*	1,101	1,018	—	2,119
Fixed income:				
U.S. Treasury, government, and agency bonds	—	599	—	599
Mortgage- and asset-backed securities	—	156	—	156
Corporate bonds	—	978	—	978
Pooled funds	—	471	—	471
Cash equivalents and other	1	223	—	224
Real estate investments	260	—	1,000	1,260
Private equity	—	—	571	571
Total	$ 2,795	$ 4,284	$ 1,571	$ 8,650
Liabilities:				
Derivatives	$ —	$ (3)	$ —	$ (3)
Total	$ 2,795	$ 4,281	$ 1,571	$ 8,647

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 1,000**	**$ 571**	$ 841	$ 593
Actual return on investments:				
Related to investments held at year end	**79**	**51**	74	8
Related to investments sold during the year	**33**	**(16)**	30	51
Total return on investments	**112**	**35**	104	59
Purchases, sales, and settlements	**9**	**(36)**	55	(81)
Ending balance	**$ 1,121**	**$ 570**	$ 1,000	$ 571

NOTES (continued)
Southern Company and Subsidiary Companies 2014 Annual Report

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
	(in millions)			
Assets:				
Domestic equity*	$ 147	$ 56	$ —	$ 203
International equity*	36	67	—	103
Fixed income:				
U.S. Treasury, government, and agency bonds	—	29	—	29
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	39	—	39
Pooled funds	—	41	—	41
Cash equivalents and other	9	27	—	36
Trust-owned life insurance	—	381	—	381
Real estate investments	11	—	37	48
Private equity	—	—	19	19
Total	$ 203	$ 646	$ 56	$ 905

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$ 157	$ 45	$ —	$ 202
International equity*	39	82	—	121
Fixed income:				
U.S. Treasury, government, and agency bonds	—	34	—	34
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	35	—	35
Pooled funds	—	46	—	46
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	369	—	369
Real estate investments	10	—	36	46
Private equity	—	—	20	20
Total	$ 206	$ 636	$ 56	$ 898

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$ 36**	**$ 20**	$ 30	$ 21
Actual return on investments:				
Related to investments held at year end	**1**	**1**	3	—
Related to investments sold during the year	**—**	**(1)**	1	2
Total return on investments	**1**	**—**	4	2
Purchases, sales, and settlements	**—**	**(1)**	2	(3)
Ending balance	**$ 37**	**$ 19**	$ 36	$ 20

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014 , 2013 , and 2012 were $87 million , $84 million , and $82 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

Insurance Recovery

Mirant Corporation (Mirant) was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and other countries. Mirant was a wholly-owned subsidiary of Southern Company until its initial public offering in 2000. In 2001, Southern Company completed a spin-off to its stockholders of its remaining ownership, and Mirant became an independent corporate entity.

In 2003, Mirant and certain of its affiliates filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. In 2005, Mirant, as a debtor in possession, and the unsecured creditors' committee filed a complaint against Southern Company. Later in 2005, this complaint was transferred to MC Asset Recovery, LLC (MC Asset Recovery) as part of Mirant's plan of reorganization. In 2009, Southern Company entered into a settlement agreement with MC Asset Recovery to resolve this action. The settlement included an agreement where Southern Company paid MC Asset Recovery $202 million . Southern Company filed an insurance claim in 2009 to recover a portion of this settlement and received payments from its insurance provider of $25 million in June 2012 and $15 million in December 2013. Additionally, legal fees related to these insurance settlements totaled approximately $6 million in 2012 and $4 million in 2013. As a result, the net reduction to expense presented as MC Asset Recovery insurance settlement in the statement of income was approximately $19 million in 2012 and $11 million in 2013.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power and Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including units co-owned by Gulf Power and Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against Georgia Power (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001. The case against Alabama Power (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. In September 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2014 was $22 million . Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the

Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. In February 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted Georgia Power's summary judgment motion, ruling that Georgia Power has no liability in the private action. In May 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of Georgia Power's regulatory treatment for environmental remediation expenses, these matters are not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $48 million as of December 31, 2014 . These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements .

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of the first lawsuit, Georgia Power recovered approximately $27 million , based on its ownership interests, and Alabama Power recovered approximately $17 million , representing the vast majority of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. In 2012, Alabama Power credited the award to cost of service for the benefit of customers. Also in 2012, Georgia Power credited the award to accounts where the original costs were charged and used it to reduce rate base, fuel, and cost of service for the benefit of customers.

On December 12, 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in the second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. Georgia Power was awarded approximately $18 million , based on its ownership interests, and Alabama Power was awarded approximately $26 million . No amounts have been recognized in the financial statements as of December 31, 2014 . The final outcome of this matter cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On March 4, 2014, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2014 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Alabama Power

Rate RSE

Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two -year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0% . If Alabama Power's actual retail return is above the allowed weighted cost of equity (WCE) range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range. Prior to 2014, retail rates remained unchanged when the retail ROE was projected to be between 13.0% and 14.5% .

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. In August 2013, the Alabama PSC voted to issue a report on Rate RSE that found that Alabama Power's Rate RSE mechanism continues to be just and reasonable to customers and Alabama Power, but recommended Alabama Power modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting Alabama Power's capital structure to an allowed equity ratio of 45% .
- Replace these two provisions with a provision that establishes rates based upon the WCE range of 5.75% to 6.21% , with an adjusting point of 5.98% . If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53% , with an adjusting point of 6.19% .
- Provide eligibility for a performance-based adder of seven basis points, or 0.07% , to the WCE adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

In August 2013, Alabama Power filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. In November 2013, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00% .

On December 1, 2014, Alabama Power submitted the required annual filing under Rate RSE to the Alabama PSC. The Rate RSE increase was 3.49% , or $181 million annually, effective January 1, 2015. The revenue adjustment includes the performance based adder of 0.07% . Under the terms of Rate RSE, the maximum increase for 2016 cannot exceed 4.51% .

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. Alabama Power may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 4, 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015. As of December 31, 2014 , Alabama Power had an under recovered certificated PPA balance of $56 million , of which $27 million is included in under recovered regulatory clause revenues and $29 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of electricity from wind-powered generating facilities that became operational in 2012. In 2012, the Alabama PSC approved and certificated a second PPA of approximately 200 MWs of electricity from other wind-powered generating facilities which became operational in 2014. The terms of the PPAs permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell the environmental attributes, separately or bundled with energy. Alabama Power has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting

Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If Alabama Power is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2014. In August 2013, the Alabama PSC approved Alabama Power's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The Rate CNP Environmental increase effective January 1, 2015 was 1.5% , or $75 million annually, based upon projected billings. As of December 31, 2014 , Alabama Power had an under recovered environmental clause balance of $49 million , of which $47 million is included in under recovered regulatory clause revenues and $2 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate ECR

Alabama Power has established energy cost recovery rates under Alabama Power's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2014, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2015 the energy cost recovery rates which began in 2011. Therefore, the Rate ECR factor as of January 1, 2015 remained at 2.681 cents per KWH. Effective with billings beginning in January 2016, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

Alabama Power's over recovered fuel costs at December 31, 2014 totaled $47 million as compared to over recovered fuel costs of $42 million at December 31, 2013 . At December 31, 2014 , $47 million is included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, Alabama Power is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of Alabama Power's approximately 12,200 MWs of generating capacity. Alabama Power also plans to cease using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. Additionally, Alabama Power expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

In accordance with an accounting order from the Alabama PSC, Alabama Power will transfer the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized through Rate CNP Environmental over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on Southern Company's financial statements.

Nuclear Waste Fund Accounting Order

In November 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. In accordance with the court's order, the DOE submitted a proposal to the U.S. Congress to change the fee to zero. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014.

On August 5, 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, Alabama Power is authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). At December 31, 2014 , Alabama Power recorded an $8 million regulatory liability which is included in other regulatory liabilities deferred in the balance sheet. Upon the DOE meeting the requirements of the Nuclear Waste Policy Act of 1982 and a new spent fuel depositary fee being put in place, the accumulated balance in the regulatory liability account will be available for purposes of the associated cost responsibility. In the event the balance is later determined to be more than needed, those amounts would be used for the benefit of customers, subject to the approval of the Alabama PSC. The ultimate outcome of this matter cannot be determined at this time.

Compliance and Pension Cost Accounting Order

In 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs would have been amortized over a three -year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing Alabama Power to fully amortize the balances in certain regulatory asset accounts, including the $28 million of compliance and pension costs accumulated at December 31, 2014 . This amortization expense was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires Alabama Power to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the compliance and pension cost accounting order. Consequently, Alabama Power will not defer any expenditures in 2015, 2016, and 2017 related to critical electric infrastructure and domestic nuclear facilities under these orders.

Non-Nuclear Outage Accounting Order

In August 2013, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three -year period beginning in 2015.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing Alabama Power to fully amortize the balances in certain regulatory asset accounts, including the $95 million of non-nuclear outage costs accumulated at December 31, 2014. This amortization expense was reflected in other operations and maintenance and was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires Alabama Power to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the non-nuclear outage accounting order.

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, Alabama Power fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset account balances amortized as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, as discussed herein.

Non-Environmental Federal Mandated Costs Accounting Order

On December 9, 2014, pending the development of a new cost recovery mechanism, the Alabama PSC issued an accounting order authorizing the deferral as a regulatory asset of up to $50 million of costs associated with non-environmental federal mandates that would otherwise impact rates in 2015.

On February 17, 2015, Alabama Power filed a proposed modification to Rate CNP Environmental with the Alabama PSC to include compliance costs for both environmental and non-environmental mandates. The non-environmental costs that would be recovered through the revised mechanism concern laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. If approved as requested, the effective date for the revised mechanism would be March 20, 2015, upon which the regulatory asset balance would be reclassified to the under recovered balance for Rate CNP Environmental, and the related customer rates would not become effective before January 2016. The ultimate outcome of this matter cannot be determined at this time.

Georgia Power

Rate Plans

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, Georgia Power increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million ; (2) Environmental Compliance Cost Recovery (ECCR) tariff by approximately $25 million ; (3) Demand-Side Management (DSM) tariffs by approximately $1 million ; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million , for a total increase in base revenues of approximately $110 million .

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million ;
- DSM tariffs by approximately $3 million ; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request.

The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2014, Georgia Power's retail ROE exceeded 12.00% , and Georgia Power expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

In July 2013, the Georgia PSC approved Georgia Power's latest triennial Integrated Resource Plan (2013 IRP) including Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (2011 IRP Update) to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) were also approved and will be effective by April 16, 2016, based on a one -year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved Georgia Power's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. Georgia Power expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. Georgia Power plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

The decertification of these units and fuel conversions are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in Georgia Power's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, Georgia Power continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million . Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC in February 2013, requiring it to use options and hedges within a 24 -month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On January 20, 2015, the Georgia PSC approved the deferral of Georgia Power's next fuel case filing until at least June 30, 2015.

Georgia Power's under recovered fuel balance totaled approximately $199 million at December 31, 2014 and is included in current assets and other deferred charges and assets. At December 31, 2013 , Georgia Power's over recovered fuel balance totaled approximately $58 million and was included in current liabilities and other deferred credits and liabilities.

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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.

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 deposit s.

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.

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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.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in millions)	
Federal —			
Current	$ 175	$ 363	$ 177
Deferred	695	386	1,011
	870	749	1,188
State —			
Current	93	(10)	61
Deferred	14	110	85
	107	100	146
Total	$ 977	$ 849	$ 1,334

Net cash payments for income taxes in 2014 , 2013 , and 2012 were $272 million , $139 million , and $38 million , respectively.

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 11,125**	$ 9,710
Property basis differences	**1,332**	1,515
Leveraged lease basis differences	**299**	287
Employee benefit obligations	**613**	491
Premium on reacquired debt	**103**	113
Regulatory assets associated with employee benefit obligations	**1,390**	705
Regulatory assets associated with AROs	**871**	824
Other	**523**	350
Total	**16,256**	13,995
Deferred tax assets —		
Federal effect of state deferred taxes	**430**	421
Employee benefit obligations	**1,675**	1,048
Over recovered fuel clause	**—**	30
Other property basis differences	**453**	157
Deferred costs	**86**	84
ITC carryforward	**480**	121
Unbilled revenue	**67**	116
Other comprehensive losses	**89**	54
AROs	**871**	824
Estimated Loss on Kemper IGCC	**631**	472
Deferred state tax assets	**117**	77
Other	**342**	220
Total	**5,241**	3,624
Valuation allowance	**(49)**	(49)
Total deferred tax assets	**5,192**	3,575
Total deferred tax liabilities, net	**11,064**	10,420
Portion included in current assets/(liabilities), net	**504**	143
Accumulated deferred income taxes	**$ 11,568**	$ 10,563

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2014 , Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $701 million , which could result in net state income tax benefits of $41 million , if utilized. However, the subsidiaries have established a valuation allowance for the entire amount due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2018 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2014 , the tax-related regulatory assets to be recovered from customers were $1.5 billion . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2014 , the tax-related regulatory liabilities to be credited to customers were $192 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

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In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $22 million in 2014 , $16 million in 2013 , and $23 million in 2012 . At December 31, 2014 , Southern Company had a federal ITC carryforward which is expected to result in $379 million of federal income tax benefit. The ITC carryforward expires in 2023, but is expected to be utilized in 2015. Additionally, Southern Company had state ITC carryforwards for the states of Georgia and Mississippi totaling $159 million , which will expire between 2020 and 2024.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2014	2013	2012
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**2.3**	2.5	2.5
Employee stock plans dividend deduction	**(1.4)**	(1.6)	(1.0)
Non-deductible book depreciation	**1.4**	1.5	0.9
AFUDC-Equity	**(2.9)**	(2.6)	(1.3)
ITC basis difference	**(1.6)**	(1.2)	(0.3)
Other	**(0.3)**	(0.5)	(0.2)
Effective income tax rate	**32.5 %**	33.1 %	35.6 %

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity. The 2014 effective tax rate decrease, as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity and an increase in tax benefits related to federal ITCs. Additionally, the 2013 effective rate decrease, as compared to 2012, is primarily due to an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 7**	$ 70	$ 120
Tax positions increase from current periods	**64**	3	13
Tax positions increase from prior periods	**102**	—	7
Tax positions decrease from prior periods	**(3)**	(66)	(56)
Reductions due to settlements	**—**	—	(10)
Reductions due to expired statute of limitations	**—**	—	(4)
Balance at end of year	**$ 170**	$ 7	$ 70

The tax positions increase from current periods and increase from prior periods for 2014 relate primarily to a deduction for R&E expenditures related to the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Section 174 Research and Experimental Deduction" for more information. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on Southern Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in millions)	
Tax positions impacting the effective tax rate	**$ 10**	$ 7	$ 5
Tax positions not impacting the effective tax rate	**160**	—	65
Balance of unrecognized tax benefits	**$ 170**	$ 7	$ 70

The tax positions impacting the effective tax rate for 2014, 2013, and 2012 relate to federal and state income tax credits. The tax positions not impacting the effective tax rate for 2014 relate to a deduction for R&E expenditures related to the Kemper IGCC. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Southern Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2008.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2014 and 2013 , which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At each of December 31, 2014 and 2013 , trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2014	2013
	(in millions)	
Senior notes	$ 2,375	$ 428
Other long-term debt	775	12
Pollution control revenue bonds	152	—
Capitalized leases	31	29
Total	$ 3,333	$ 469

Maturities through 2019 applicable to total long-term debt are as follows: $3.33 billion in 2015 ; $1.83 billion in 2016 ; $1.55 billion in 2017 ; $862 million in 2018 ; and $1.21 billion in 2019 .

Subsequent to December 31, 2014, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035 that will occur on March 16, 2015.

Bank Term Loans

Southern Company and certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month LIBOR. At December 31, 2014 , Mississippi Power had outstanding bank term loans totaling $775 million , which are reflected in the statements of capitalization as long-term debt. At December 31, 2013 , Mississippi Power had outstanding bank term loans totaling $525 million and Georgia Power had outstanding bank term loans totaling $400 million .

In January 2014, Mississippi Power entered into an 18 -month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

In February 2014, Georgia Power repaid three four -month floating rate bank loans in an aggregate principal amount of $400 million .

In June 2014, Southern Company entered into a 90 -day floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the investment by Southern Company in its subsidiaries. This bank loan was repaid in August 2014.

The outstanding bank loans as of December 31, 2014, all of which relate to Mississippi Power, have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014 , Mississippi Power was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of Georgia Power under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, Georgia Power, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which Georgia Power may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility will be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

All borrowings under the FFB Credit Facility are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

On February 20, 2014, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion . The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million , which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million . The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

Senior Notes

Southern Company and its subsidiaries issued a total of $1.4 billion of senior notes in 2014 . Southern Company issued $750 million and its subsidiaries issued a total of $600 million . The proceeds of these issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs.

At December 31, 2014 and 2013 , Southern Company and its subsidiaries had a total of $18.2 billion and $17.3 billion , respectively, of senior notes outstanding. At December 31, 2014 and 2013 , Southern Company had a total of $2.2 billion and $1.8 billion , respectively, of senior notes outstanding.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.2 billion of outstanding pollution control revenue bonds at December 31, 2014 and 2013 . The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. See "Assets Subject to Lien" herein for additional information.

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

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In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of Mississippi Power. In May 2014 and August 2014, the MBFC issued $12.3 million and $10.5 million , respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of Mississippi Power and proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2014 and 2013 . Mississippi Power had no obligation at December 31, 2014 and $11.3 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013 . Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Mississippi Power's agreements relating to its taxable revenue bonds include covenants limiting debt levels consistent with those described above under "Bank Term Loans."

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service and the related obligations are classified as long-term debt.

In September 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2014 of approximately $80 million with an annual interest rate of 4.9% . Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

At December 31, 2014 and 2013 , the capitalized lease obligations for Georgia Power's corporate headquarters building were $40 million and $45 million , respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2014 and 2013 , Alabama Power had a capitalized lease obligation of $5 million for a natural gas pipeline with an annual interest rate of 6.9% .

At December 31, 2014 and 2013 , a subsidiary of Southern Company had capital lease obligations of approximately $34 million and $30 million , respectively, for certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.4% to 3.2% .

Other Obligations

In 2012, January 2014, and October 2014, Mississippi Power received $150 million , $75 million , and $50 million , respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $41 million as of December 31, 2014 .

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See "Plant Daniel Revenue Bonds" herein for additional information.

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of Georgia Power that are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

Bank Credit Arrangements

At December 31, 2014 , committed credit arrangements with banks were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2015	2016	2017	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				(in millions)		(in millions)		(in millions)	
Southern Company	$ —	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	228	50	—	1,030	1,308	1,308	58	—	58	170
Georgia Power	—	150	—	1,600	1,750	1,736	—	—	—	—
Gulf Power	80	165	30	—	275	275	50	—	50	30
Mississippi Power	135	165	—	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	488	—	—	—	—
Other	70	—	—	—	70	70	20	—	20	50
Total	$ 513	$ 530	$ 30	$ 4,130	$ 5,203	$ 5,177	$ 153	$ 40	$ 193	$ 320

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than $^1/_4$ of 1% for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew their bank credit arrangements as needed, prior to expiration.

Most of these bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities and, for Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014 , Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

A portion of the $5.2 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $1.8 billion . In addition, at December 31, 2014 , the traditional operating companies had $476 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of Georgia Power were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" for additional information.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014:		
Commercial paper	**$ 803**	**0.3%**
Short-term bank debt	**—**	**—%**
Total	**$ 803**	**0.3%**
December 31, 2013:		
Commercial paper	$ 1,082	0.2%
Short-term bank debt	400	0.9%
Total	$ 1,482	0.4%

Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "noncontrolling interest," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

There were no changes for the years ended December 31, 2014 and 2013 in redeemable preferred stock of subsidiaries for Southern Company.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2014 , 2013 , and 2012 , the traditional operating companies and Southern Power incurred fuel expense of $6.0 billion , $5.5 billion , and $5.1 billion , respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.

In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $198 million , $157 million , and $171 million for 2014 , 2013 , and 2012 , respectively.

Estimated total obligations under these commitments at December 31, 2014 were as follows:

	Operating Leases [(1)]	Other
	(in millions)	
2015	$ 230	$ 11
2016	234	11
2017	264	10
2018	270	7
2019	274	6
2020 and thereafter	1,980	50
Total	$ 3,252	$ 95

(1) A total of $1.1 billion of biomass PPAs included under operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $118 million , $123 million , and $155 million for 2014 , 2013 , and 2012 , respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2014 , estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2015	$ 50	$ 50	$ 100
2016	41	48	89
2017	18	47	65
2018	9	35	44
2019	6	23	29
2020 and thereafter	20	228	248
Total	$ 144	$ 431	$ 575

For the traditional operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $53 million . At the termination of the leases, the lessee may renew the lease or exercise its purchase option or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

In December 2013, Georgia Power entered into an agreement that requires Georgia Power to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2014 , Southern Company issued approximately 20.8 million shares of common stock (including approximately 5.0 million treasury shares) for approximately $806 million through the employee and director stock plans and the Southern Investment Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

From August 2013 through December 2014, Southern Company used shares held in treasury, to the extent available, and newly issued shares to satisfy the requirements under the Southern Investment Plan and the employee savings plan. Beginning in January 2015, Southern Company ceased issuing additional shares under the Southern Investment Plan and the employee savings plan. All sales under these plans are now being funded with shares acquired on the open market by the independent plan administrators.

Beginning in 2015, Southern Company expects to repurchase shares of common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises. The Southern Company Board of Directors has approved the repurchase of up to 20 million shares of common stock for such purpose until December 31, 2017. Repurchases may be made by means of open market purchases, privately negotiated transactions, or accelerated or other share repurchase programs, in accordance with applicable securities laws.

Shares Reserved

At December 31, 2014 , a total of 93 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance shares units as discussed below). Of the total 93 million shares reserved, there were 15 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2014 .

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2014 , there were 5,437 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2014**	2013	2012
Expected volatility	**14.6%**	16.6%	17.7%
Expected term *(in years)*	**5**	5	5
Interest rate	**1.5%**	0.9%	0.9%
Dividend yield	**4.9%**	4.4%	4.2%
Weighted average grant-date fair value	**$2.20**	$2.93	$3.39

Southern Company's activity in the stock option program for 2014 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2013	38,819,366	$38.64
Granted	12,812,691	41.40
Exercised	11,585,363	35.06
Cancelled	117,375	42.72
Outstanding at December 31, 2014	**39,929,319**	**$40.55**
Exercisable at December 31, 2014	**20,695,310**	**$38.76**

The number of stock options vested, and expected to vest in the future, as of December 31, 2014 was not significantly different from the number of stock options outstanding at December 31, 2014 as stated above. As of December 31, 2014 , the weighted average remaining contractual term for the options outstanding and options exercisable was approximately seven years and six years , respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $342 million and $214 million , respectively.

As of December 31, 2014 , there was $10 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 16 months .

For the years ended December 31, 2014 , 2013 , and 2012 , total compensation cost for stock option awards recognized in income was $27 million , $25 million , and $23 million , respectively, with the related tax benefit also recognized in income of $10 million , $10 million , and $9 million , respectively.

The total intrinsic value of options exercised during the years ended December 31, 2014 , 2013 , and 2012 was $125 million , $77 million , and $162 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $48 million , $30 million , and $62 million for the years ended December 31, 2014 , 2013 , and 2012 , respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2014 , 2013 , and 2012 was $400 million , $204 million , and $397 million , respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three -year performance period which equates to the requisite service period. Employees that retire prior to the end of the three -year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three -year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

NOTES (continued)
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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.

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.

NOTES (continued)
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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.

NOTES (continued)
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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 proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trusts do not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. These commingled funds, along with other equity and debt commingled funds held in Alabama Power's nuclear decommissioning trusts, primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection. See Note 1 under "Nuclear Decommissioning" for additional information.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2014	**$ 24,015**	**$ 25,816**
2013	$ 21,650	$ 22,197

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 herein for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in commodity fuel prices and prices of electricity because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales from its uncontracted generating capacity. Further, the traditional operating companies may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted wholesale generating capacity is used to sell electricity.

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014 , the net volume of energy-related derivative contracts for natural gas positions totaled 244 million mmBtu for the Southern Company system, with the longest hedge date of 2019 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2017 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 6 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness.

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At December 31, 2014 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$200	3-month LIBOR	2.93%	October 2025	$ (8)
	350	3-month LIBOR	2.57%	May 2025	(6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	1
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$2,050				$ (16)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Any ineffectiveness is recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. At December 31, 2014 , there were no foreign currency derivatives outstanding.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 7**	$ 16	Other current liabilities	**$ 118**	$ 26
	Other deferred charges and assets	**—**	7	Other deferred credits and liabilities	**79**	29
Total derivatives designated as hedging instruments for regulatory purposes		**$ 7**	$ 23		**$ 197**	$ 55
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 7**	$ 3	Other current liabilities	**$ 17**	$ —
	Other deferred charges and assets	**1**	—	Other deferred credits and liabilities	**7**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 8**	$ 3		**$ 24**	$ —
Derivatives not designated as hedging instruments						
Energy-related derivatives	Other current assets	**$ 6**	$ —	Other current liabilities	**$ 4**	$ 1
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**—**	—
Total derivatives not designated as hedging instruments		**$ 6**	$ 1		**$ 4**	$ 1
Total		**$ 21**	$ 27		**$ 225**	$ 56

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

Fair Value					
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [a]	**$ 13**	$ 24	Energy-related derivatives presented in the Balance Sheet [a]	**$ 201**	$ 56
Gross amounts not offset in the Balance Sheet [b]	**(9)**	(22)	Gross amounts not offset in the Balance Sheet [b]	**(9)**	(22)
Net energy-related derivative assets	**$ 4**	$ 2	**Net energy-related derivative liabilities**	**$ 192**	$ 34
Interest rate derivatives presented in the Balance Sheet [a]	**$ 8**	$ 3	Interest rate derivatives presented in the Balance Sheet [a]	**$ 24**	$ —
Gross amounts not offset in the Balance Sheet [b]	**(8)**	—	Gross amounts not offset in the Balance Sheet [b]	**(8)**	—
Net interest rate derivative assets	**$ —**	**$ 3**	**Net interest rate derivative liabilities**	**$ 16**	**$ —**

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (118)**	$ (26)	Other regulatory liabilities, current	**$ 7**	$ 16
	Other regulatory assets, deferred	**(79)**	(29)	Other regulatory liabilities, deferred	**—**	7
Total energy-related derivative gains (losses)		**$ (197)**	$ (55)		**$ 7**	$ 23

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for Southern Company. Furthermore, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes to the carrying value of long-term debt and the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from OCI into earnings were immaterial for Southern Company.

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of energy-related and foreign currency derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company.

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses was associated with hedging fuel price risk of certain PPA customers and had no impact on net income or on fuel expense as presented in the Company's statements of income for the years ended December 31, 2014 , 2013 , and 2012 . This third party hedging activity has been discontinued.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2014 , Southern Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014 , the fair value of derivative liabilities with contingent features was $54 million . The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

Southern Company, the traditional operating companies, and Southern Power are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional operating companies, and Southern Power only enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Southern Company, the traditional operating companies, and Southern Power have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional operating companies', and Southern Power's exposure to counterparty credit risk. Therefore, Southern Company, the traditional operating companies, and Southern Power do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies – Alabama Power, Georgia Power, Gulf Power and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Southern Company's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $383 million , $346 million , and $425 million in 2014 , 2013 , and 2012 , respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2014 , 2013 , and 2012 was as follows:

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	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2014							
Operating revenues	**$ 17,354**	**$ 1,501**	**$ (449)**	**$ 18,406**	**$ 159**	**$ (98)**	**$ 18,467**
Depreciation and amortization	**1,709**	**220**	**—**	**1,929**	**16**	**—**	**1,945**
Interest income	**17**	**1**	**—**	**18**	**3**	**(2)**	**19**
Interest expense	**705**	**89**	**—**	**794**	**43**	**(2)**	**835**
Income taxes	**1,056**	**(3)**	**—**	**1,053**	**(76)**	**—**	**977**
Segment net income (loss) [(a)] [(b)]	**1,797**	**172**	**—**	**1,969**	**(3)**	**(3)**	**1,963**
Total assets	**64,644**	**5,550**	**(131)**	**70,063**	**1,156**	**(296)**	**70,923**
Gross property additions	**5,568**	**942**	**—**	**6,510**	**11**	**1**	**6,522**
2013							
Operating revenues	$ 16,136	$ 1,275	$ (376)	$ 17,035	$ 139	$ (87)	$ 17,087
Depreciation and amortization	1,711	175	—	1,886	15	—	1,901
Interest income	17	1	—	18	2	(1)	19
Interest expense	714	74	—	788	36	—	824
Income taxes	889	46	—	935	(85)	(1)	849
Segment net income (loss) [(a)] [(b)]	1,486	166	—	1,652	(10)	2	1,644
Total assets	59,447	4,429	(101)	63,775	1,077	(306)	64,546
Gross property additions	5,226	633	—	5,859	9	—	5,868
2012							
Operating revenues	$ 15,730	$ 1,186	$ (438)	$ 16,478	$ 141	$ (82)	$ 16,537
Depreciation and amortization	1,629	143	—	1,772	15	—	1,787
Interest income	21	1	—	22	19	(1)	40
Interest expense	757	63	—	820	39	—	859
Income taxes	1,307	93	—	1,400	(66)	—	1,334
Segment net income (loss) [(a)]	2,145	175	1	2,321	33	(4)	2,350
Total assets	58,600	3,780	(129)	62,251	1,116	(218)	63,149
Gross property additions	4,813	241	—	5,054	5	—	5,059

(a) After dividends on preferred and preference stock of subsidiaries.

(b) Segment net income (loss) for the traditional operating companies in 2014 and 2013 includes $868 million in pre-tax charges ($536 million after tax) and $1.2 billion in pre-tax charges ($729 million after tax), respectively, for estimated probable losses on the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
			(in millions)	
2014	**$15,550**	**$2,184**	**$672**	**$18,406**
2013	14,541	1,855	639	17,035
2012	14,187	1,675	616	16,478

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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			Trading Price Range	
				Basic Earnings	Diluted Earnings	Dividends	High	Low
		(in millions)						
March 2014	**$ 4,644**	**$ 700**	**$ 351**	**$ 0.39**	**$ 0.39**	**$ 0.5075**	**$ 44.00**	**$ 40.27**
June 2014	**4,467**	**1,103**	**611**	**0.68**	**0.68**	**0.5250**	**46.81**	**42.55**
September 2014	**5,339**	**1,278**	**718**	**0.80**	**0.80**	**0.5250**	**45.47**	**41.87**
December 2014	**4,017**	**561**	**283**	**0.31**	**0.31**	**0.5250**	**51.28**	**43.55**
March 2013	$ 3,897	$ 325	$ 81	$ 0.09	$ 0.09	$ 0.4900	$ 46.95	$ 42.82
June 2013	4,246	640	297	0.34	0.34	0.5075	48.74	42.32
September 2013	5,017	1,491	852	0.97	0.97	0.5075	45.75	40.63
December 2013	3,927	799	414	0.47	0.47	0.5075	42.94	40.03

As a result of the revisions to the cost estimate for the Kemper IGCC, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, and $540.0 million ($333.5 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014 . See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

The Southern Company system's business is influenced by seasonal weather conditions.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2010 through 2014
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions)	**$ 18,467**	$ 17,087	$ 16,537	$ 17,657	$ 17,456
Total Assets (in millions)	**$ 70,923**	$ 64,546	$ 63,149	$ 59,267	$ 55,032
Gross Property Additions (in millions)	**$ 6,522**	$ 5,868	$ 5,059	$ 4,853	$ 4,443
Return on Average Common Equity (percent)	**10.08**	8.82	13.10	13.04	12.71
Cash Dividends Paid Per Share of Common Stock	**$ 2.0825**	$ 2.0125	$ 1.9425	$ 1.8725	$ 1.8025
Consolidated Net Income After Preferred and Preference Stock of Subsidiaries (in millions)	**$ 1,963**	$ 1,644	$ 2,350	$ 2,203	$ 1,975
Earnings Per Share —					
Basic	**$ 2.19**	$ 1.88	$ 2.70	$ 2.57	$ 2.37
Diluted	**2.18**	1.87	2.67	2.55	2.36
Capitalization (in millions):					
Common stock equity	**$ 19,949**	$ 19,008	$ 18,297	$ 17,578	$ 16,202
Preferred and preference stock of subsidiaries and noncontrolling interest	**977**	756	707	707	707
Redeemable preferred stock of subsidiaries	**375**	375	375	375	375
Redeemable noncontrolling interest	**39**	—	—	—	—
Long-term debt	**20,841**	21,344	19,274	18,647	18,154
Total (excluding amounts due within one year)	**$ 42,181**	$ 41,483	$ 38,653	$ 37,307	$ 35,438
Capitalization Ratios (percent):					
Common stock equity	**47.3**	45.8	47.3	47.1	45.7
Preferred and preference stock of subsidiaries and noncontrolling interest	**2.3**	1.8	1.8	1.9	2.0
Redeemable preferred stock of subsidiaries	**0.9**	0.9	1.0	1.0	1.1
Redeemable noncontrolling interest	**0.1**	—	—	—	—
Long-term debt	**49.4**	51.5	49.9	50.0	51.2
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 21.98**	$ 21.43	$ 21.09	$ 20.32	$ 19.21
Market price per share:					
High	**$ 51.28**	$ 48.74	$ 48.59	$ 46.69	$ 38.62
Low	**43.55**	40.03	41.75	35.73	30.85
Close (year-end)	**49.11**	41.11	42.81	46.29	38.23
Market-to-book ratio (year-end) (percent)	**223.4**	191.8	203.0	227.8	199.0
Price-earnings ratio (year-end) (times)	**22.4**	21.9	15.9	18.0	16.1
Dividends paid (in millions)	**$ 1,866**	$ 1,762	$ 1,693	$ 1,601	$ 1,496
Dividend yield (year-end) (percent)	**4.2**	4.9	4.5	4.0	4.7
Dividend payout ratio (percent)	**95.0**	107.1	72.0	72.7	75.7
Shares outstanding (in thousands):					
Average	**897,194**	876,755	871,388	856,898	832,189
Year-end	**907,777**	887,086	867,768	865,125	843,340
Stockholders of record (year-end)	**137,369**	143,800	149,628	155,198	160,426
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,890**	3,859	3,832	3,809	3,813
Commercial*	**587**	582	579	578	579
Industrial*	**16**	16	16	16	15
Other	**11**	10	9	9	10

Total	**4,504**	4,467	4,436	4,412	4,417
Employees (year-end)	**26,369**	26,300	26,439	26,377	25,940

* A reclassification of customers from commercial to industrial is reflected for years 2010-2013 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
For the Periods Ended December 2010 through 2014
Southern Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	**$ 6,499**	$ 6,011	$ 5,891	$ 6,268	$ 6,319
Commercial	**5,469**	5,214	5,097	5,384	5,252
Industrial	**3,449**	3,188	3,071	3,287	3,097
Other	**133**	128	128	132	123
Total retail	**15,550**	14,541	14,187	15,071	14,791
Wholesale	**2,184**	1,855	1,675	1,905	1,994
Total revenues from sales of electricity	**17,734**	16,396	15,862	16,976	16,785
Other revenues	**733**	691	675	681	671
Total	**$ 18,467**	$ 17,087	$ 16,537	$ 17,657	$ 17,456
Kilowatt-Hour Sales (in millions):					
Residential	**53,347**	50,575	50,454	53,341	57,798
Commercial	**53,243**	52,551	53,007	53,855	55,492
Industrial	**54,140**	52,429	51,674	51,570	49,984
Other	**909**	902	919	936	943
Total retail	**161,639**	156,457	156,054	159,702	164,217
Wholesale sales	**32,786**	26,944	27,563	30,345	32,570
Total	**194,425**	183,401	183,617	190,047	196,787
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.18**	11.89	11.68	11.75	10.93
Commercial	**10.27**	9.92	9.62	10.00	9.46
Industrial	**6.37**	6.08	5.94	6.37	6.20
Total retail	**9.62**	9.29	9.09	9.44	9.01
Wholesale	**6.66**	6.88	6.08	6.28	6.12
Total sales	**9.12**	8.94	8.64	8.93	8.53
Average Annual Kilowatt-Hour					
Use Per Residential Customer	**13,765**	13,144	13,187	13,997	15,176
Average Annual Revenue					
Per Residential Customer	**$ 1,679**	$ 1,562	$ 1,540	$ 1,645	$ 1,659
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	**46,549**	45,502	45,740	43,555	42,961
Maximum Peak-Hour Demand (megawatts):					
Winter	**37,234**	27,555	31,705	34,617	35,593
Summer	**35,396**	33,557	35,479	36,956	36,321
System Reserve Margin (at peak) (percent)*	**19.8**	21.5	20.8	19.2	23.3
Annual Load Factor (percent)	**59.6**	63.2	59.5	59.0	62.2
Plant Availability (percent):**					
Fossil-steam	**85.8**	87.7	89.4	88.1	91.4
Nuclear	**91.5**	91.5	94.2	93.0	92.1
Source of Energy Supply (percent):					
Coal	**39.3**	36.9	35.2	48.7	55.0
Nuclear	**14.8**	15.5	16.2	15.0	14.1
Hydro	**2.5**	3.9	1.7	2.1	2.5
Oil and gas	**37.4**	37.3	38.3	28.0	23.7
Purchased power	**6.0**	6.4	8.6	6.2	4.7
Total	**100.0**	100.0	100.0	100.0	100.0

*

** Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

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.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2014 Annual Report

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	**2014**	2013	**2014**	2013
	(in billions)				
Residential	**18.7**	**4.5%**	1.7%	**(0.8)%**	(1.1)%
Commercial	**14.1**	**1.6**	(0.5)	**(1.3)**	0.5
Industrial	**23.8**	**3.9**	3.4	**3.9**	3.4
Other	**0.2**	**—**	(1.4)	**—**	(1.4)
Total retail	**56.8**	**3.5**	1.8	**1.0 %**	1.1 %
Wholesale —					
Non-affiliates	**4.6**	**12.3**	(10.8)		
Affiliates	**5.7**	**(21.7)**	88.9		
Total wholesale	**10.3**	**(9.4)**	34.5		
Total energy sales	**67.1**	**1.3%**	6.3%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2014 were 3.5% higher than in 2013. Residential and commercial sales increased 4.5% and 1.6%, respectively, due primarily to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Weather-adjusted residential and commercial sales decreased 0.8% and 1.3%, respectively, due primarily to a decrease in customer demand in 2014 compared to 2013. Industrial sales increased 3.9% in 2014 compared to 2013 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, automotive and plastics, and stone, clay, and glass sectors. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

Retail energy sales in 2013 were 1.8% higher than in 2012. Residential sales increased 1.7%, due primarily to more favorable weather in 2013. Weather-adjusted residential sales decreased 1.1% in 2013, primarily due to a decrease in customer demand. Commercial sales and weather-adjusted commercial sales remained relatively flat in 2013 compared to 2012. Industrial sales increased 3.4% in 2013 compared to 2012 as a result of an increase in demand resulting from changes in production levels primarily in the chemicals, primary metals, and stone, clay, and glass sectors.

Weather adjusted wholesale non-affiliate KWH sales decreased 8.0% in 2014 and 11.0% in 2013 due primarily to a decrease in demand from municipalities. See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2014	2013	2012
Total generation *(billions of KWHs)*	**63.6**	65.3	59.9
Total purchased power *(billions of KWHs)*	**6.6**	4.0	5.4
Sources of generation *(percent)* —			
Coal	**54**	53	53
Nuclear	**23**	21	25
Gas	**17**	17	18
Hydro	**6**	9	4
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.14**	3.29	3.30
Nuclear	**0.84**	0.84	0.80
Gas	**3.69**	3.38	3.06
Average cost of fuel, generated *(cents per net KWH)* *	**2.68**	2.73	2.61
Average cost of purchased power *(cents per net KWH)* **	**5.92**	5.76	4.86

* KWHs generated by hydro are excluded from the average cost of fuel, generated.

** Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

Fuel and purchased power expenses were $2.0 billion in 2014, an increase of $130 million, or 7.0%, compared to 2013. The increase was primarily due to a $147 million increase related to the volume of KWHs purchased and a $10 million increase in the average cost of purchased power. These increases were partially offset by a $19 million decrease in the average cost of fuel and an $8 million decrease in the volume of KWHs generated.

Fuel and purchased power expenses were $1.9 billion in 2013, an increase of $102 million, or 5.8%, compared to 2012. The increase was primarily due to a $95 million increase in the volume of KWHs generated, a $38 million increase in the average cost of fuel, and a $37 million increase in the average cost of purchased power. These increases were partially offset by a $68 million decrease related to the volume of KWHs purchased.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's energy cost recovery clause. The Company, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate ECR" for additional information.

Fuel

Fuel expenses were $1.6 billion in 2014, a decrease of $26 million, or 1.6%, compared to 2013. The decrease was primarily due to a 4.5% decrease in the average cost of KWHs generated by coal, partially offset by a 30.8% decrease in the volume of KWHs generated by hydro facilities as a result of less rainfall, and a 9.2% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements. Fuel expenses were $1.6 billion in 2013, an increase of $128 million, or 8.5%, compared to 2012. This increase was primarily due to a 10.5% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements, and a 9.9% increase in KWHs generated by coal. This was partially offset by a 110.9% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

Purchased Power – Non-Affiliates

In 2014, purchased power expense from non-affiliates was $185 million, an increase of $85 million, or 85.0%, compared to 2013. The increase was primarily due to a 42.1% increase in the average cost per KWH purchased primarily due to demand during peak periods and a 28.8% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014 and the addition of a new PPA in 2014. In 2013, purchased power expense from non-affiliates was $100 million, an increase of $27 million, or 37.0%, compared to 2012. The increase over the prior year was primarily due to a 52.6% increase in the amount of energy purchased, partially offset by a 17.2% decrease in the average cost per KWH.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $200 million in 2014, an increase of $71 million, or 55.0%, compared to 2013. This increase was primarily due to a 96.4% increase in the amount of energy purchased to meet the demand created during cold weather in the first quarter 2014, partially offset by a 20.8% decrease in the average cost per KWH purchased due to the availability of lower cost Southern Company system generation at the time of purchase. Purchased power expense from affiliates was $129 million in 2013, a decrease of $53 million, or 29.1%, compared to 2012. This decrease was primarily due to a 50.4% decrease in the amount of energy purchased, partially offset by a 42.5% increase in the average cost per KWH.

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $179 million, or 13.9%, as compared to the prior year. Steam production, other power generation, and hydro generation expenses increased $110 million primarily due to scheduled outage costs. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information. Distribution and transmission expenses increased $31 million primarily related to increases in maintenance and labor expenses. Nuclear production expenses increased $14 million primarily related to labor expenses.

Depreciation and Amortization

Depreciation and amortization decreased $42 million, or 6.5%, in 2014 as compared to the prior year. The decrease in 2014 was primarily due to the amortization of $120 million of the regulatory liability for other cost of removal obligations, partially offset by increases due to depreciation rates related to environmental assets and amortization of certain regulatory assets. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost of Removal Accounting Order" for additional information. In 2013, depreciation and amortization increased $6 million, or 0.9%, as compared to the prior year. The increase in 2013 was primarily due to an increase in depreciation related to environmental assets, additions to property, plant, and equipment related to distribution and transmission projects, as well as the amortization of software. These increases were partially offset by the deferral of certain expenses under an accounting order. See Note 3 to the financial statements under "Retail Regulatory Matters – Compliance and Pension Cost Accounting Order" for additional information. The increase related to environmental assets was offset by revenues under Rate CNP Environmental.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $17 million, or 53.1%, in 2014 as compared to the prior year primarily due to an increase in capital expenditures related to environmental and steam generation. AFUDC equity increased $13 million, or 68.4%, in 2013 as compared to the prior year primarily due to increased capital expenditures associated with environmental, steam and nuclear generating facilities, and transmission. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $28 million, or 9.8%, in 2013. The decrease in 2013 was primarily due to a decrease in interest rates and the timing of issuances and redemptions of long-term debt.

Other Income (Expense), Net

Other income (expense), net increased $14 million, or 38.9%, in 2014 as compared to the prior year primarily due to a decrease in non-operating expenses and an increase in sales of non-utility property. Other income (expense), net decreased $12 million, or 50.0%, in 2013 as compared to the prior year primarily due to increases in donations, partially offset by increases in non-operating income related to gains on sales of non-utility property.

Income Taxes

Income taxes increased $34 million, or 7.1%, in 2014 as compared to the prior year primarily due to higher pre-tax earnings.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the Company had invested approximately $3.6 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $355 million, $184 million, and $62 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with existing environmental statutes and regulations will total approximately $641 million from 2015 through 2017, with annual totals of approximately $417 million, $171 million, and $53 million for 2015, 2016, and 2017, respectively. Costs related to the proposed water and final CCR rules are not included in the estimated environmental capital expenditures. See "Capital Requirements and Contractual Obligations" for additional information regarding estimated incremental environmental compliance expenditures. In addition, these estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters –Environmental Accounting Order" herein for additional information on planned unit retirements and fuel conversions at the Company.

Southern Electric Generating Company (SEGCO) is jointly owned with Georgia Power. As part of its environmental compliance strategy, SEGCO expects to complete the addition of natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Georgia Power through a PPA. If such compliance costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial condition and results of operations. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $3.4 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS , and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred its designation decision for one area in Alabama, so future nonattainment designation of this area is possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units. In March 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of the Company and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. The Company believes this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units co-owned with Mississippi Power and units owned by SEGCO, which is jointly owned with Georgia Power.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

These proposed and final water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at six generating plants. In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the State of Alabama has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $311 million and ongoing post-closure care of approximately $49 million . The Company will record asset retirement obligations (ARO) for the estimated closure costs required under the CCR Rule during 2015. SEGCO, which is jointly owned with Georgia Power, will also record an ARO for ash ponds commonly used at Plant E.C. Gaston. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state

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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.

Income Tax Matters

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $165 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $65 million to $70 million for the 2015 tax year.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $23 million in 2014, $47 million in 2013 and $6 million in 2012. Postretirement benefit costs for the Company were $4 million, $7 million, and $10 million in 2014, 2013, and 2012, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial position, results of operations, or cash flows.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $156 million and $22 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $20 million and $2 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $8 million or less change in total annual benefit expense and a $113 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2014 as compared to December 31, 2013. No contributions to the qualified pension plan were made for the year ended December 31, 2014. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015 . The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2018. See Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $1.7 billion for 2014, a decrease of $205 million as compared to 2013. The decrease in cash provided from operating activities was primarily due to an increase in income tax payments and the timing of fossil fuel stock purchases, partially offset by the timing of payment of accounts payable. Net cash provided from operating activities totaled $1.9 billion for 2013, an increase of $538 million as compared to 2012. The increase in cash provided from operating activities was primarily due to changes in timing of fossil fuel stock purchases and payment of accounts payable, and collection of fuel cost recovery revenues.

Net cash used for investing activities totaled $1.6 billion for 2014, $1.1 billion for 2013, and $0.9 billion for 2012. In 2014, these additions were primarily due to gross property additions related to environmental, distribution, transmission, steam generation, and nuclear fuel. In 2013, these additions were primarily due to gross property additions related to steam generation, distribution, and transmission equipment. In 2012, these additions were primarily due to gross property additions related to nuclear fuel and transmission, distribution, and steam generating equipment.

Net cash used for financing activities totaled $164 million in 2014 primarily due to the payment of common stock dividends, and issuances and redemptions of securities. Net cash used for financing activities totaled $614 million in 2013 primarily due to the payment of common stock dividends, and the issuance and a maturity of senior notes. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2014 included an increase of $854 million in property, plant, and equipment primarily due to additions to environmental, distribution, transmission, and steam generation. Other significant changes included increases of $454 million in securities due within one year and $418 million in other regulatory assets, deferred related to pension and other postretirement benefits.

The Company's ratio of common equity to total capitalization, including short-term debt, was 45.6% in 2014 and 44.3% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2014, the Company had approximately $273 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires [(a)]					Executable Term-Loans		Due Within One Year	
2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$ 228	$ 50	$ 1,030	$ 1,308	$ 1,308	$ 58	$ —	$ 58	$ 170

(a) No credit arrangements expire in 2017.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. The Company expects to renew its bank credit arrangements as needed, prior to expiration.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2014, the Company had $784 million of outstanding variable rate pollution control revenue bonds requiring liquidity support. In addition, at December 31, 2014, the Company had $280 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2014:					
Commercial paper	**$—**	**—%**	**$13**	**0.2%**	**$300**
December 31, 2013:					
Commercial paper	$—	—%	$11	0.2%	$90
December 31, 2012:					
Commercial paper	$—	—%	$6	0.2%	$57

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

The Company believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

In August 2014, the Company issued $400 million aggregate principal amount of Series 2014A 4.150% Senior Notes due August 15, 2044. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

During 2014, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $200 million.

In December 2014, the Company incurred obligations related to the issuance of $254 million of The Industrial Development Board of the Town of Columbia, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 2014 – A, 2014 – B, 2014 – C, and 2014 – D due December 1, 2037. The proceeds were used to refund, in December 2014, approximately $254 million of The Industrial Development Board of the Town of Columbia, Pollution Control Revenue Refunding Bonds (Alabama Power Company Project), Series 1995 – A, 1995 – B, 1995 – C, 1995 – D, 1995 – E, 1996 – A, 1999 – A, 1999 – B, and 1999 – C.

Subsequent to December 31, 2014, the Company announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035, which will occur on March 16, 2015.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2014, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $365 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash.

Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $984 million of long-term variable interest rate exposure at January 1, 2015 was 0.71%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $10 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

In addition, Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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 grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Over the next three years, the Company estimates spending, as part of its base level capital investment, $515 million on Plant Farley (including nuclear fuel), $892 million on distribution facilities, and $556 million on transmission additions. These base level capital investment amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Costs related to proposed water and final CCR rules are not included in the construction program base level capital investment. In addition, these estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information. The Company's base level construction program investments including investments to comply with existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and final CCR rules over the 2015 through 2017 three-year period, based on the final CCR rule which will continue to regulate CCR as non-hazardous solid waste, are estimated as follows:

	2015	2016	2017
Construction program:		*(in millions)*	
Base capital	$ 1,114	$ 857	$ 1,092
Existing environmental statutes and regulations	417	171	53
Total construction program base level capital investment	$ 1,531	$ 1,028	$ 1,145
Estimated incremental environmental compliance investments:			
Proposed water and final CCR rules	$ 4	$ 88	$ 239

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

At December 31, 2014, in addition to the funds required for the Company's construction program, approximately $454 million will be required by the end of 2015 for maturities of long-term debt. Subsequent to December 31, 2014, the Company announced the redemption of $250 million aggregate principal amount of its Series DD 5.65% Senior Notes due March 15, 2035 that will occur on March 16, 2015, which increased the total funds required for maturities of long-term debt by the end of 2015 to $704 million. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Alabama PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 454	$ 761	$ 200	$ 5,216	$ 6,631
Interest	259	503	435	3,436	4,633
Preferred and preference stock dividends [(b)]	39	79	79	—	197
Financial derivative obligations [(c)]	40	21	—	—	61
Operating leases [(d)]	16	24	11	17	68
Capital Lease	—	1	1	3	5
Purchase commitments —					
Capital [(e)]	1,343	2,281	—	—	3,624
Fuel [(f)]	1,297	1,705	867	529	4,398
Purchased power [(g)]	68	144	156	854	1,222
Other [(h)]	45	81	81	365	572
Pension and other postretirement benefit plans [(i)]	18	33	—	—	51
Total	$ 3,579	$ 5,633	$ 1,830	$ 10,420	$ 21,462

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and are included in purchased power.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and final CCR rules, which are approximately $4 million, $88 million, and $239 million for 2015, 2016, and 2017, respectively. These amounts also exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

(h) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan , postretirement benefit plan , and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water , CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, pending EPA civil action against the Company, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards ;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
Alabama Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 5,249**	$ 4,952	$ 4,933
Wholesale revenues, non-affiliates	**281**	248	277
Wholesale revenues, affiliates	**189**	212	111
Other revenues	**223**	206	199
Total operating revenues	**5,942**	5,618	5,520
Operating Expenses:			
Fuel	**1,605**	1,631	1,503
Purchased power, non-affiliates	**185**	100	73
Purchased power, affiliates	**200**	129	182
Other operations and maintenance	**1,468**	1,289	1,287
Depreciation and amortization	**603**	645	639
Taxes other than income taxes	**356**	348	340
Total operating expenses	**4,417**	4,142	4,024
Operating Income	**1,525**	1,476	1,496
Other Income and (Expense):			
Allowance for equity funds used during construction	**49**	32	19
Interest income	**15**	16	16
Interest expense, net of amounts capitalized	**(255)**	(259)	(287)
Other income (expense), net	**(22)**	(36)	(24)
Total other income and (expense)	**(213)**	(247)	(276)
Earnings Before Income Taxes	**1,312**	1,229	1,220
Income taxes	**512**	478	477
Net Income	**800**	751	743
Dividends on Preferred and Preference Stock	**39**	39	39
Net Income After Dividends on Preferred and Preference Stock	**$ 761**	$ 712	$ 704

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
Alabama Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Net Income	**$ 800**	$ 751	$ 743
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(3), $-, and $(7), respectively	**(5)**	—	(11)
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**2**	1	2
Total other comprehensive income (loss)	**(3)**	1	(9)
Comprehensive Income	**$ 797**	$ 752	$ 734

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014 , 2013 , and 2012
Alabama Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Activities:			
Net income	**$ 800**	$ 751	$ 743
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**724**	816	767
Deferred income taxes	**270**	198	164
Allowance for equity funds used during construction	**(49)**	(32)	(19)
Pension, postretirement, and other employee benefits	**(61)**	9	(21)
Stock based compensation expense	**11**	10	9
Other, net	**17**	(38)	(24)
Changes in certain current assets and liabilities —			
-Receivables	**(58)**	2	23
-Fossil fuel stock	**61**	146	(132)
-Materials and supplies	**(17)**	19	(21)
-Other current assets	**(11)**	5	(4)
-Accounts payable	**157**	35	(77)
-Accrued taxes	**(199)**	(23)	(12)
-Accrued compensation	**50**	(23)	(3)
-Retail fuel cost over recovery	**5**	42	1
-Other current liabilities	**9**	(3)	(18)
Net cash provided from operating activities	**1,709**	1,914	1,376
Investing Activities:			
Property additions	**(1,457)**	(1,107)	(867)
Nuclear decommissioning trust fund purchases	**(245)**	(280)	(194)
Nuclear decommissioning trust fund sales	**244**	279	193
Cost of removal net of salvage	**(77)**	(47)	(33)
Change in construction payables	**(10)**	(13)	12
Other investing activities	**(22)**	26	(45)
Net cash used for investing activities	**(1,567)**	(1,142)	(934)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**28**	24	27
Pollution control bonds	**254**	—	—
Senior notes issuances	**400**	300	1,000
Redemptions —			
Pollution control revenue bonds	**(254)**	—	(1)
Senior notes	**—**	(250)	(950)
Payment of preferred and preference stock dividends	**(39)**	(39)	(39)
Payment of common stock dividends	**(550)**	(644)	(684)
Other financing activities	**(3)**	(5)	(2)
Net cash used for financing activities	**(164)**	(614)	(649)
Net Change in Cash and Cash Equivalents	**(22)**	158	(207)
Cash and Cash Equivalents at Beginning of Year	**295**	137	344
Cash and Cash Equivalents at End of Year	**$ 273**	$ 295	$ 137
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18, $11 and $7 capitalized, respectively)	**$ 231**	$ 243	$ 273

Income taxes (net of refunds)	**436**	296	309
Noncash transactions — accrued property additions at year-end	**8**	18	31

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
Alabama Power Company 2014 Annual Report

Assets	2014	2013
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 273	$ 295
Receivables —		
Customer accounts receivable	345	341
Unbilled revenues	138	142
Under recovered regulatory clause revenues	74	—
Other accounts and notes receivable	23	30
Affiliated companies	37	54
Accumulated provision for uncollectible accounts	(9)	(8)
Fossil fuel stock, at average cost	268	329
Materials and supplies, at average cost	406	375
Vacation pay	65	63
Prepaid expenses	244	57
Other regulatory assets, current	84	54
Other current assets	5	6
Total current assets	1,953	1,738
Property, Plant, and Equipment:		
In service	23,080	22,092
Less accumulated provision for depreciation	8,522	8,114
Plant in service, net of depreciation	14,558	13,978
Nuclear fuel, at amortized cost	348	332
Construction work in progress	1,006	748
Total property, plant, and equipment	15,912	15,058
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	66	54
Nuclear decommissioning trusts, at fair value	756	714
Miscellaneous property and investments	84	80
Total other property and investments	906	848
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	525	519
Prepaid pension costs	—	276
Deferred under recovered regulatory clause revenues	31	25
Other regulatory assets, deferred	1,063	645
Other deferred charges and assets	162	142
Total deferred charges and other assets	1,781	1,607
Total Assets	$ 20,552	$ 19,251

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
Alabama Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	**2014**	2013
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 454**	$ —
Accounts payable —		
Affiliated	**248**	198
Other	**443**	339
Customer deposits	**87**	85
Accrued taxes —		
Accrued income taxes	**2**	11
Other accrued taxes	**37**	33
Accrued interest	**66**	61
Accrued vacation pay	**54**	53
Accrued compensation	**131**	74
Other regulatory liabilities, current	**2**	37
Other current liabilities	**80**	41
Total current liabilities	**1,604**	932
Long-Term Debt (See accompanying statements)	**6,176**	6,233
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,874**	3,603
Deferred credits related to income taxes	**72**	75
Accumulated deferred investment tax credits	**125**	133
Employee benefit obligations	**326**	195
Asset retirement obligations	**829**	730
Other cost of removal obligations	**744**	828
Other regulatory liabilities, deferred	**239**	259
Deferred over recovered regulatory clause revenues	**47**	15
Other deferred credits and liabilities	**79**	61
Total deferred credits and other liabilities	**6,335**	5,899
Total Liabilities	**14,115**	13,064
Redeemable Preferred Stock (See accompanying statements)	**342**	342
Preference Stock (See accompanying statements)	**343**	343
Common Stockholder's Equity (See accompanying statements)	**5,752**	5,502
Total Liabilities and Stockholder's Equity	**$ 20,552**	$ 19,251
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
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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		
Long-term notes payable —				
0.55% due 2015	**400**	400		
5.20% due 2016	**200**	200		
5.50% to 5.55% due 2017	**525**	525		
5.13% due 2019	**200**	200		
3.375% to 6.125% due 2020-2044	**3,950**	3,550		
Total long-term notes payable	**5,275**	4,875		
Other long-term debt —				
Pollution control revenue bonds —				
0.28% to 5.00% due 2034	**367**	367		
Variable rate (0.03% at 1/1/15) due 2015	**54**	54		
Variable rates (0.04% to 0.06% at 1/1/15) due 2017	**36**	36		
Variable rates (0.01% to 0.06% at 1/1/15) due 2021-2038	**694**	694		
Total other long-term debt	**1,151**	1,151		
Capitalized lease obligations	**5**	5		
Unamortized debt discount, net	**(7)**	(4)		
Total long-term debt (annual interest requirement — $259 million)	**6,630**	6,233		
Less amount due within one year	**454**	—		
Long-term debt excluding amount due within one year	**6,176**	6,233	**49.0%**	50.2%
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	**48**	48		
$1 par value — 5.20% to 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 12,000,000 shares: $25 stated value				
(annual dividend requirement — $18 million)	**294**	294		
Total redeemable preferred stock	**342**	342	**2.7**	2.7
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 5.63% to 6.50%				
— 14,000,000 shares (noncumulative): $25 stated value				
(annual dividend requirement — $21 million)	**343**	343	**2.7**	2.8
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized — 40,000,000 shares				
Outstanding — 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**2,304**	2,262		
Retained earnings	**2,255**	2,044		
Accumulated other comprehensive loss	**(29)**	(26)		
Total common stockholder's equity	**5,752**	5,502	**45.6**	44.3

Total Capitalization	**$ 12,613**	$ 12,420	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014 , 2013 , and 2012
Alabama Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2011	31	$ 1,222	$ 2,182	$ 1,956	$ (18)	$ 5,342
Net income after dividends on preferred and preference stock	—	—	—	704	—	704
Capital contributions from parent company	—	—	45	—	—	45
Other comprehensive income (loss)	—	—	—	—	(9)	(9)
Cash dividends on common stock	—	—	—	(684)	—	(684)
Balance at December 31, 2012	31	1,222	2,227	1,976	(27)	5,398
Net income after dividends on preferred and preference stock	—	—	—	712	—	712
Capital contributions from parent company	—	—	35	—	—	35
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(644)	—	(644)
Balance at December 31, 2013	**31**	**1,222**	**2,262**	**2,044**	**(26)**	**5,502**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**761**	**—**	**761**
Capital contributions from parent company	**—**	**—**	**42**	**—**	**—**	**42**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(3)**	**(3)**
Cash dividends on common stock	**—**	**—**	**—**	**(550)**	**—**	**(550)**
Balance at December 31, 2014	**31**	**$ 1,222**	**$ 2,304**	**$ 2,255**	**$ (29)**	**$ 5,752**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2014 Annual Report

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of 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

impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Rate ECR" and "Retail Regulatory Matters – Rate CNP" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel.

See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee Accounting Order" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2014	2013
	(in millions)	
Generation	**$ 11,670**	$ 11,314
Transmission	**3,579**	3,287
Distribution	**6,196**	5,934
General	**1,623**	1,545
Plant acquisition adjustment	**12**	12
Total plant in service	**$ 23,080**	$ 22,092

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.

Nuclear Outage Accounting Order

In accordance with an Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over a subsequent 18 -month period with the fall outage costs amortization beginning in January of the following year and the spring outage costs amortization beginning in July of the same year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2014 and 3.2% in 2013 and 2012 . Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2014, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2015. The study was also provided to the Alabama PSC.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

	2014	2013
	(in millions)	
Balance at beginning of year	**$ 730**	$ 589
Liabilities incurred	**1**	—
Liabilities settled	**(3)**	(1)
Accretion	**45**	40
Cash flow revisions	**56**	102
Balance at end of year	**$ 829**	$ 730

The cash flow revisions in 2014 are primarily related to the Company's AROs associated with asbestos at its steam generation facilities. The cash flow revisions in 2013 are primarily related to revisions to the nuclear decommissioning ARO based on the Company's updated decommissioning study.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $311 million and ongoing post-closure care of approximately $49 million . The Company will record AROs for the estimated closure costs required under the CCR Rule during 2015. SEGCO, which is jointly owned with Georgia Power, will also record an ARO for ash ponds commonly used at Plant E.C. Gaston. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

The NRC requires licensees of commercial 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.

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)

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

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

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	48%	**48%**	47%
International equity	20	**20**	20
Domestic fixed income	24	**26**	27
Special situations	1	**—**	—
Real estate investments	4	**4**	4
Private equity	3	**2**	2
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance (TOLI).*** Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.

- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2014 and 2013 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

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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.

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*	$ 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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	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*	$ 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.

	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:				
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	Private Equity	Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	$ 13	$ 7	$ 11	$ 8
Actual return on investments:				
Related to investments held at year end	—	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	—	—	1	—
Purchases, sales, and settlements	—	—	1	(1)
Ending balance	$ 13	$ 7	$ 13	$ 7

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014 , 2013 , and 2012 were $21 million , $20 million , and $19 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for the Company on all remaining claims and dismissal of the case with prejudice in 2011. In September 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of the Company, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

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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% .
- Provide eligibility for a performance-based adder of seven basis points, or 0.07% , to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

In August 2013, the Company filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. In November 2013, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00% .

On December 1, 2014, the Company submitted the required annual filing under Rate RSE to the Alabama PSC. The Rate RSE increase was 3.49% , or $181 million annually, effective January 1, 2015. The revenue adjustment includes the performance based adder of 0.07% . Under the terms of Rate RSE, the maximum increase for 2016 cannot exceed 4.51% .

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP. The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. On March 4, 2014, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2014 through March 31, 2015. It is anticipated that no adjustment will be made to Rate CNP PPA in 2015. As of December 31, 2014 , the Company had an under recovered certificated PPA balance of $56 million , of which $27 million is included in under recovered regulatory clause revenues and $29 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of electricity from wind-powered generating facilities that became operational in 2012. In 2012, the Alabama PSC approved and certificated a second PPA of approximately 200 MWs of electricity from other wind-powered generating facilities which became operational in 2014. The terms of the PPAs permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell the environmental attributes, separately or bundled with energy. The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets was previously under review by the SEC at the request of the electric utility industry. In June 2014, the SEC requested the Financial Accounting Standards Board to address the issue through the Emerging Issues Task Force (EITF). Any accounting decisions will now be subject to EITF deliberations. The outcome of the EITF's deliberations cannot be determined at this time. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2014. In August 2013, the Alabama PSC approved the Company's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The Rate CNP Environmental increase effective January 1, 2015 was 1.5% , or $75 million annually, based upon projected billings. As of December 31, 2014 , the Company had an under recovered environmental clause balance of $49 million , of which $47 million is included in under recovered regulatory clause revenues and $2 million is included in deferred under recovered regulatory clause revenues in the balance sheet.

Rate ECR

The Company has established energy cost recovery rates under the Company's Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. In December 2014, the Alabama PSC issued a consent order that the Company leave in effect for 2015 the energy cost recovery rates which began in 2011. Therefore, the Rate ECR factor as of January 1, 2015 remained at 2.681 cents per KWH. Effective with billings beginning in January 2016, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2014 totaled $47 million as compared to over recovered fuel costs of $42 million at December 31, 2013. At December 31, 2014, $47 million is included in deferred over recovered regulatory clause revenues. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery or return of fuel costs.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24 -month period. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million . The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Environmental Accounting Order

Based on an order from the Alabama PSC, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

As part of its environmental compliance strategy, the Company plans to retire Plant Gorgas Units 6 and 7. These units represent 200 MWs of the Company's approximately 12,200 MWs of generating capacity. The Company also plans to cease using coal at Plant Barry Units 1 and 2 (250 MWs), but such units will remain available on a limited basis with natural gas as the fuel source. Additionally, the Company expects to cease using coal at Plant Barry Unit 3 (225 MWs) and Plant Greene County Units 1 and 2 (300 MWs) and begin operating those units solely on natural gas. These plans are expected to be effective no later than April 2016.

In accordance with an accounting order from the Alabama PSC, the Company will transfer the unrecovered plant asset balances to a regulatory asset at their respective retirement dates. The regulatory asset will be amortized through Rate CNP Environmental over the remaining useful lives, as established prior to the decision for retirement. As a result, these decisions will not have a significant impact on the Company's financial statements.

Nuclear Waste Fund Accounting Order

In November 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. In accordance with the court's order, the DOE submitted a proposal to the U.S. Congress to change the fee to zero. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014.

On August 5, 2014, the Alabama PSC issued an order to provide for the continued recovery from customers of amounts associated with the permanent disposal of nuclear waste from the operation of Plant Farley. In accordance with the order, effective May 16, 2014, the Company is authorized to recover from customers an amount equal to the prior fee and to record the amounts in a regulatory liability account (approximately $14 million annually). At December 31, 2014, the Company recorded an $8 million regulatory liability which is included in other regulatory liabilities deferred in the balance sheet. Upon the DOE meeting the requirements of the Nuclear Waste Policy Act of 1982 and a new spent fuel depositary fee being put in place, the accumulated balance in the regulatory liability account will be available for purposes of the associated cost responsibility. In the event the balance is later determined to be more than needed, those amounts would be used for the benefit of customers, subject to the approval of the Alabama PSC. The ultimate outcome of this matter cannot be determined at this time.

Compliance and Pension Cost Accounting Order

In 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs would have been amortized over a three -year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing the Company to fully amortize the balances in certain regulatory asset accounts, including the $28 million of compliance and pension costs accumulated at December 31, 2014. This amortization expense was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires the Company to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the compliance and pension cost accounting order. Consequently, the Company will not defer any expenditures in 2015, 2016, and 2017 related to critical electric infrastructure and domestic nuclear facilities under these orders.

Non-Nuclear Outage Accounting Order

In August 2013, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three -year period beginning in 2015.

On November 3, 2014, the Alabama PSC issued an accounting order authorizing the Company to fully amortize the balances in certain regulatory asset accounts, including the $95 million of non-nuclear outage costs accumulated at December 31, 2014. This amortization expense was reflected in other operations and maintenance and was offset by the amortization of the regulatory liability for other cost of removal obligations. See "Cost of Removal Accounting Order" herein for additional information. The cost of removal accounting order requires the Company to terminate, as of December 31, 2014, the regulatory asset accounts created pursuant to the non-nuclear outage accounting order.

Cost of Removal Accounting Order

In accordance with an accounting order issued on November 3, 2014 by the Alabama PSC, at December 31, 2014, the Company fully amortized the balance of $123 million in certain regulatory asset accounts and offset this amortization expense with the amortization of $120 million of the regulatory liability for other cost of removal obligations. The regulatory asset account balances amortized as of December 31, 2014 represented costs previously deferred under a compliance and pension cost accounting order as well as a non-nuclear outage accounting order, as discussed herein.

Non-Environmental Federal Mandated Costs Accounting Order

On December 9, 2014, pending the development of a new cost recovery mechanism, the Alabama PSC issued an accounting order authorizing the deferral as a regulatory asset of up to $50 million of costs associated with non-environmental federal mandates that would otherwise impact rates in 2015.

On February 17, 2015, the Company filed a proposed modification to Rate CNP Environmental with the Alabama PSC to include compliance costs for both environmental and non-environmental mandates. The non-environmental costs that would be recovered through the revised mechanism concern laws, regulations, and other mandates directed at the utility industry involving the security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. If approved as requested, the effective date for the revised mechanism would be March 20, 2015, upon which the regulatory asset balance would be reclassified to the under recovered balance for Rate CNP Environmental, and the related customer rates would not become effective before January 2016. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $84 million in 2014 , $88 million in 2013 , and $109 million in 2012 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. The Company has guaranteed $100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. The Company had guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes, which matured on May 15, 2013. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guarantee.

At December 31, 2014 , the capitalization of SEGCO consisted of $106 million of equity and $125 million of long-term debt on which the annual interest requirement is $3 million . In addition, SEGCO had short-term debt outstanding of $42 million . SEGCO paid dividends of $3 million in 2014 , $7 million in 2013 , and $14 million in 2012 , of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO plans to add natural gas as the primary fuel source for 1,000 MWs of its generating capacity in 2015. A natural gas pipeline was constructed and will be placed in service in 2015. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of the gas pipeline. The Company will own 14% of the pipeline with the remaining 86% owned by SEGCO. At December 31, 2014 , the Company's portion of the construction work in progress associated with the pipeline is $15 million .

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2014 were as follows:

Facility	Total MW Capacity	Company Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
				(in millions)	
Greene County	500	60.00% (1)	$ 164	$ 96	$ 1
Plant Miller					
Units 1 and 2	1,320	91.84% (2)	1,512	561	14

(1) Jointly owned with an affiliate, Mississippi Power.

(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

The Company has contracted to operate and maintain the jointly-owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Tennessee. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in millions)	
Federal —			
Current	**$ 198**	$ 243	$ 262
Deferred	**225**	160	137
	423	403	399
State —			
Current	**44**	36	51
Deferred	**45**	39	27
	89	75	78
Total	**$ 512**	$ 478	$ 477

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 3,429**	$ 3,187
Property basis differences	**457**	458
Premium on reacquired debt	**30**	33
Employee benefit obligations	**215**	209
Regulatory assets associated with employee benefit obligations	**366**	198
Asset retirement obligations	**59**	38
Regulatory assets associated with asset retirement obligations	**285**	265
Other	**156**	128
Total	**4,997**	4,516
Deferred tax assets —		
Federal effect of state deferred taxes	**219**	205
Unbilled fuel revenue	**42**	41
Storm reserve	**27**	32
Employee benefit obligations	**400**	231
Other comprehensive losses	**19**	18
Asset retirement obligations	**344**	303
Other	**90**	108
Total	**1,141**	938
Total deferred tax liabilities, net	**3,856**	3,578
Portion included in current assets/(liabilities), net	**18**	25
Accumulated deferred income taxes	**$ 3,874**	$ 3,603

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

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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.

Bank Credit Arrangements

At December 31, 2014 , committed credit arrangements with banks were as follows:

Expires (a)					Executable Term-Loans		Due Within One Year	
2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$228	$ 50	$ 1,030	$ 1,308	$ 1,308	$ 58	$ —	$ 58	$ 170

(a) No credit arrangements expire in 2017.

The Company expects to renew its bank credit agreements as needed, prior to expiration. Most of the bank credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1 / 10 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2014 , the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $784 million as of December 31, 2014 . In addition, at December 31, 2014, the Company had $280 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2014 and 2013 , there was no short-term debt outstanding. At December 31, 2014 , the Company had regulatory approval to have outstanding up to $2 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $1.6 billion , $1.6 billion , and $1.5 billion , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $37 million , $30 million , and $33 million for 2014, 2013, and 2012, respectively. Total estimated minimum long-term obligations at December 31, 2014 were as follows:

	Operating Lease PPAs
	(in millions)
2015	$ 37
2016	39
2017	40
2018	41
2019	43
2020 and thereafter	137
Total commitments	$ 337

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $18 million in 2014 , $21 million in 2013 , and $24 million in 2012 . Of these amounts, $14 million , $18 million , and $19 million for 2014, 2013, and 2012, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
		(in millions)	
2015	$ 13	$ 3	$ 16
2016	11	3	14
2017	7	3	10
2018	5	1	6
2019	5	—	5
2020 and thereafter	17	—	17
Total	$ 58	$ 10	$ 68

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $5 million in 2015, $4 million in 2016, and $12 million in 2020 and thereafter. There are no obligations under these leases in 2017, 2018, and 2019. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

The Company has guaranteed the obligation of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in November 2013, which mature in December 2018. Georgia

Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to Georgia Power's then proportionate ownership of SEGCO's stock if the Company is called upon to make such payment under its guarantee. See Note 4 for additional information.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014 , there were approximately 1,000 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 2,027,298 shares, 1,319,038 shares, and 1,099,315 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20 , $2.93 , and $3.39 , respectively.

For the years ended December 31, 2014 , 2013 , and 2012 , total compensation cost for stock option awards recognized in income was $5 million , $4 million , and $4 million , respectively, with the related tax benefit also recognized in income of $2 million , $2 million , and $1 million , respectively. The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. As of December 31, 2014 , there was $1 million of unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 15 months .

The total intrinsic value of options exercised during the years ended December 31, 2014 , 2013 , and 2012 was $21 million , $11 million , and $28 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $8 million , $4 million , and $11 million for the years ended December 31, 2014 , 2013 , and 2012 , respectively. As of December 31, 2014 , the aggregate intrinsic value for the options outstanding and options exercisable was $55 million and $37 million , respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three -year performance period which equates to the requisite service period. Employees that retire prior to the end of the three -year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three -year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014 , 2013 , and 2012, employees of the Company were granted performance share units of 176,070 , 141,355 , and 131,820 , respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54 , $40.50 , and $41.99 , respectively.

The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014 , 2013 , and 2012, total compensation cost for performance share units recognized in income was $5 million annually, with the related tax benefit of $2 million annually also recognized in income. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014 , there was $5 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months .

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. On April 1, 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years . The Company purchases limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $50 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

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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.

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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:				
Equity – commingled funds	$ 63	None	Daily/Monthly	Daily/7 days
Trust – owned life insurance	115	None	Daily	15 days
Debt – commingled funds	15	None	Daily	5 days
Cash equivalents:				
Money market funds	162	None	Daily	Not applicable
As of December 31, 2013:				
Nuclear decommissioning trusts:				
Equity – commingled funds	$ 65	None	Daily/Monthly	Daily/7 days
Trust – owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	236	None	Daily	Not applicable

The nuclear decommissioning trusts include investments in TOLI. The taxable nuclear decommissioning trusts invest in the TOLI in order to minimize the impact of taxes on the portfolios and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trusts do not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. These commingled funds, along with other equity and debt commingled funds held in the nuclear decommissioning trusts, primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2014	**$ 6,631**	**$ 7,321**
2013	$ 6,228	$ 6,534

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014 , the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
56	2017	—

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to revenue and fuel expense for the 12-month period ending December 31, 2015 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

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At December 31, 2014 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$200	3-month LIBOR	2.93%	October 2025	$ (8)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are $3 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 1**	$ 5	Other current liabilities	**$ 32**	$ 3
	Other deferred charges and assets	**—**	2	Other deferred credits and liabilities	**21**	5
Total derivatives designated as hedging instruments for regulatory purposes		**$ 1**	$ 7		**$ 53**	$ 8
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	**$ —**	**$ —**	Other current liabilities	**$ 8**	**$ —**
Total		**$ 1**	$ 7		**$ 61**	$ 8

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

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The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure table below.

Fair Value					
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 1**	$ 7	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 53**	$ 8
Gross amounts not offset in the Balance Sheet [(b)]	**—**	(5)	Gross amounts not offset in the Balance Sheet [(b)]	**—**	(5)
Net energy-related derivative assets	**$ 1**	$ 2	**Net energy-related derivative liabilities**	**$ 53**	$ 3

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013 , the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (32)**	$ (3)	Other current liabilities	**$ 1**	$ 5
	Other regulatory assets, deferred	**(21)**	(5)	Other regulatory liabilities, deferred	**—**	2
Total energy-related derivative gains (losses)		**$ (53)**	$ (8)		**$ 1**	$ 7

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2014**	2013	2012	**Statements of Income Location**	**2014**	2013	2012
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (8)**	$ —	$ (18)	Interest expense, net of amounts capitalized	**$ (3)**	$ (3)	$ (3)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014 , the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014 , the fair value of derivative liabilities with contingent features was $18 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2014	**$ 1,508**	**$ 381**	**$ 187**
June 2014	**1,437**	**357**	**173**
September 2014	**1,669**	**520**	**282**
December 2014	**1,328**	**267**	**119**
March 2013	$ 1,308	$ 307	$ 141
June 2013	1,392	357	173
September 2013	1,604	500	258
December 2013	1,314	312	140

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2010 - 2014
Alabama Power Company 2014 Annual Report

		2014		2013		2012		2011		2010
Operating Revenues (in millions)	**$**	**5,942**	$	5,618	$	5,520	$	5,702	$	5,976
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$**	**761**	$	712	$	704	$	708	$	707
Cash Dividends on Common Stock (in millions)	**$**	**550**	$	644	$	684	$	774	$	586
Return on Average Common Equity (percent)		**13.52**		13.07		13.10		13.19		13.31
Total Assets (in millions)	**$**	**20,552**	$	19,251	$	18,712	$	18,477	$	17,994
Gross Property Additions (in millions)	**$**	**1,543**	$	1,204	$	940	$	1,016	$	956
Capitalization (in millions):										
Common stock equity	**$**	**5,752**	$	5,502	$	5,398	$	5,342	$	5,393
Preference stock		**343**		343		343		343		343
Redeemable preferred stock		**342**		342		342		342		342
Long-term debt		**6,176**		6,233		5,929		5,632		5,987
Total (excluding amounts due within one year)	**$**	**12,613**	$	12,420	$	12,012	$	11,659	$	12,065
Capitalization Ratios (percent):										
Common stock equity		**45.6**		44.3		44.9		45.8		44.7
Preference stock		**2.7**		2.8		2.9		2.9		2.9
Redeemable preferred stock		**2.7**		2.7		2.8		2.9		2.8
Long-term debt		**49.0**		50.2		49.4		48.4		49.6
Total (excluding amounts due within one year)		**100.0**		100.0		100.0		100.0		100.0
Customers (year-end):										
Residential		**1,247,061**		1,241,998		1,237,730		1,231,574		1,235,128
Commercial		**197,082**		196,209		196,177		196,270		197,336
Industrial		**6,032**		5,851		5,839		5,844		5,770
Other		**753**		751		748		746		782
Total		**1,450,928**		1,444,809		1,440,494		1,434,434		1,439,016
Employees (year-end)		**6,935**		6,896		6,778		6,632		6,552

SELECTED FINANCIAL AND OPERATING DATA 2010 - 2014 (continued)
Alabama Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	**$ 2,209**	$ 2,079	$ 2,068	$ 2,144	$ 2,283
Commercial	**1,533**	1,477	1,491	1,495	1,535
Industrial	**1,480**	1,369	1,346	1,306	1,231
Other	**27**	27	28	27	27
Total retail	**5,249**	4,952	4,933	4,972	5,076
Wholesale — non-affiliates	**281**	248	277	287	465
Wholesale — affiliates	**189**	212	111	244	236
Total revenues from sales of electricity	**5,719**	5,412	5,321	5,503	5,777
Other revenues	**223**	206	199	199	199
Total	**$ 5,942**	$ 5,618	$ 5,520	$ 5,702	$ 5,976
Kilowatt-Hour Sales (in millions):					
Residential	**18,726**	17,920	17,612	18,650	20,417
Commercial	**14,118**	13,892	13,963	14,173	14,719
Industrial	**23,799**	22,904	22,158	21,666	20,622
Other	**211**	211	214	214	216
Total retail	**56,854**	54,927	53,947	54,703	55,974
Wholesale — non-affiliates	**3,588**	3,711	4,196	4,330	8,655
Wholesale — affiliates	**6,713**	7,672	4,279	7,211	6,074
Total	**67,155**	66,310	62,422	66,244	70,703
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.80**	11.60	11.74	11.50	11.18
Commercial	**10.86**	10.63	10.68	10.55	10.43
Industrial	**6.22**	5.98	6.07	6.03	5.97
Total retail	**9.23**	9.02	9.14	9.09	9.07
Wholesale	**4.56**	4.04	4.58	4.60	4.76
Total sales	**8.52**	8.16	8.52	8.31	8.17
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,051**	14,451	14,252	15,138	16,570
Residential Average Annual Revenue Per Customer	**$ 1,775**	$ 1,676	$ 1,674	$ 1,740	$ 1,853
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,761**	9,347	10,285	11,553	11,349
Summer	**11,054**	10,692	11,096	11,500	11,488
Annual Load Factor (percent)	**61.4**	64.9	61.3	60.6	62.6
Plant Availability (percent)*:					
Fossil-steam	**82.5**	87.3	88.6	88.7	92.9
Nuclear	**93.3**	90.7	94.5	94.7	88.4
Source of Energy Supply (percent):					
Coal	**49.0**	50.0	48.2	52.5	56.6
Nuclear	**20.7**	20.3	22.6	20.8	17.7
Hydro	**5.5**	8.1	4.1	4.6	5.0
Gas	**15.4**	15.7	16.8	15.3	14.0
Purchased power —					
From non-affiliates	**3.6**	2.9	2.0	0.9	1.6
From affiliates	**5.8**	3.0	6.3	5.9	5.1

Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2014 Annual Report

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2014 Annual Report

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2014 Annual Report

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.

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, 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 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.

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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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	Maturity	
	Fair Value	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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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;

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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
Georgia Power Company 2014 Annual Report

	2014	2013	2012
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 8,240**	$ 7,620	$ 7,362
Wholesale revenues, non-affiliates	**335**	281	281
Wholesale revenues, affiliates	**42**	20	20
Other revenues	**371**	353	335
Total operating revenues	**8,988**	8,274	7,998
Operating Expenses:			
Fuel	**2,547**	2,307	2,051
Purchased power, non-affiliates	**287**	224	315
Purchased power, affiliates	**701**	660	666
Other operations and maintenance	**1,902**	1,654	1,644
Depreciation and amortization	**846**	807	745
Taxes other than income taxes	**409**	382	374
Total operating expenses	**6,692**	6,034	5,795
Operating Income	**2,296**	2,240	2,203
Other Income and (Expense):			
Allowance for equity funds used during construction	**45**	30	53
Interest expense, net of amounts capitalized	**(348)**	(361)	(366)
Other income (expense), net	**(22)**	5	(17)
Total other income and (expense)	**(325)**	(326)	(330)
Earnings Before Income Taxes	**1,971**	1,914	1,873
Income taxes	**729**	723	688
Net Income	**1,242**	1,191	1,185
Dividends on Preferred and Preference Stock	**17**	17	17
Net Income After Dividends on Preferred and Preference Stock	**$ 1,225**	$ 1,174	$ 1,168

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
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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
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	2014	2013	2012
		(in millions)	
Operating Activities:			
Net income	$ 1,242	$ 1,191	$ 1,185
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	1,019	979	912
Deferred income taxes	352	476	377
Allowance for equity funds used during construction	(45)	(30)	(53)
Retail fuel cost over recovery — long-term	(44)	(123)	123
Pension, postretirement, and other employee benefits	19	66	21
Pension and postretirement funding	(156)	(8)	(12)
Other, net	39	38	(12)
Changes in certain current assets and liabilities —			
-Receivables	(248)	(58)	205
-Fossil fuel stock	303	250	(269)
-Prepaid income taxes	(216)	(17)	(7)
-Other current assets	(37)	40	(53)
-Accounts payable	16	67	(165)
-Accrued taxes	17	(14)	(76)
-Accrued compensation	62	(37)	(18)
-Retail fuel cost over-recovery — short-term	(14)	(49)	107
-Other current liabilities	54	(5)	30
Net cash provided from operating activities	2,363	2,766	2,295
Investing Activities:			
Property additions	(2,023)	(1,743)	(1,723)
Investment in restricted cash from pollution control bonds	—	(89)	(284)
Distribution of restricted cash from pollution control bonds	—	89	284
Nuclear decommissioning trust fund purchases	(671)	(706)	(852)
Nuclear decommissioning trust fund sales	669	705	850
Cost of removal, net of salvage	(65)	(59)	(82)
Change in construction payables, net of joint owner portion	(54)	(67)	(149)
Prepaid long-term service agreements	(70)	(18)	(34)
Other investing activities	8	(2)	17
Net cash used for investing activities	(2,206)	(1,890)	(1,973)
Financing Activities:			
Increase (decrease) in notes payable, net	(891)	1,047	(513)
Proceeds —			
Capital contributions from parent company	549	37	42
Pollution control revenue bonds issuances and remarketings	40	194	284
Senior notes issuances	—	850	2,300
FFB loan	1,200	—	—
Redemptions and repurchases —			
Pollution control revenue bonds	(37)	(298)	(284)
Senior notes	—	(1,775)	(850)
Other long-term debt	—	—	(250)
Payment of preferred and preference stock dividends	(17)	(17)	(17)
Payment of common stock dividends	(954)	(907)	(983)
FFB loan issuance costs	(49)	(5)	(3)

Other financing activities	**(4)**	(17)	(16)
Net cash used for financing activities	**(163)**	(891)	(290)
Net Change in Cash and Cash Equivalents	**(6)**	(15)	32
Cash and Cash Equivalents at Beginning of Year	**30**	45	13
Cash and Cash Equivalents at End of Year	**$ 24**	$ 30	$ 45
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18, $14 and $21 capitalized, respectively)	**$ 319**	$ 344	$ 337
Income taxes (net of refunds)	**507**	298	312
Noncash transactions — accrued property additions at year-end	**154**	208	261

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
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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
Georgia Power Company 2014 Annual Report

	2014	2013	2014	2013
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.56% to 0.63% at 1/1/15) due 2016	**450**	450		
0.625% to 5.25% due 2015	**1,050**	1,050		
3.00% due 2016	**250**	250		
5.70% due 2017	**450**	450		
5.40% due 2018	**250**	250		
4.25% due 2019	**500**	500		
2.85% to 5.95% due 2022-2043	**3,975**	3,975		
Total long-term notes payable	**6,925**	6,925		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 4.00% due 2022-2049	**818**	818		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015	**98**	—		
Variable rate (0.04% at 1/1/15) due 2016	**4**	4		
Variable rate (0.04% at 1/1/14) due 2018	**—**	20		
Variable rates (0.01% to 0.09% at 1/1/15) due 2022-2052	**763**	838		
FFB loans (3.00% to 3.86%) due 2044	**1,200**	—		
Total other long-term debt	**2,883**	1,680		
Capitalized lease obligations	**40**	45		
Unamortized debt discount	**(11)**	(12)		
Total long-term debt (annual interest requirement — $342 million)	**9,837**	8,638		
Less amount due within one year	**1,154**	5		
Long-term debt excluding amount due within one year	**8,683**	8,633	**44.8%**	46.7%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized — 50,000,000 shares				
Outstanding — 1,800,000 shares	**45**	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized — 15,000,000 shares				
Outstanding — 2,250,000 shares	**221**	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	**266**	266	**1.4**	1.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**6,196**	5,633		
Retained earnings	**3,835**	3,565		
Accumulated other comprehensive loss	**(8)**	(5)		
Total common stockholder's equity	**10,421**	9,591	**53.8**	51.9
Total Capitalization	**$ 19,370**	$ 18,490	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014 , 2013 , and 2012
Georgia Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in millions)			
Balance at December 31, 2011	9	$ 398	$ 5,522	$ 3,112	$ (9)	$ 9,023
Net income after dividends on preferred and preference stock	—	—	—	1,168	—	1,168
Capital contributions from parent company	—	—	63	—	—	63
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(983)	—	(983)
Balance at December 31, 2012	9	398	5,585	3,297	(7)	9,273
Net income after dividends on preferred and preference stock	—	—	—	1,174	—	1,174
Capital contributions from parent company	—	—	48	—	—	48
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(907)	—	(907)
Other	—	—	—	1	—	1
Balance at December 31, 2013	**9**	**398**	**5,633**	**3,565**	**(5)**	**9,591**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**1,225**	**—**	**1,225**
Capital contributions from parent company	**—**	**—**	**563**	**—**	**—**	**563**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**(3)**	**(3)**
Cash dividends on common stock	**—**	**—**	**—**	**(954)**	**—**	**(954)**
Other	**—**	**—**	**—**	**(1)**	**—**	**(1)**
Balance at December 31, 2014	**9**	**$ 398**	**$ 6,196**	**$ 3,835**	**$ (8)**	**$ 10,421**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2014 Annual Report

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Georgia Power Company 2014 Annual Report

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 .

NOTES (continued)
Georgia Power Company 2014 Annual Report

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2014	2013	Note
	(in millions)		
Retiree benefit plans	**$ 1,325**	$ 691	(a, j)
Deferred income tax charges	**668**	684	(b, j)
Deferred income tax charges — Medicare subsidy	**34**	38	(c)
Loss on reacquired debt	**163**	181	(d, j)
Asset retirement obligations	**108**	137	(b, j)
Fuel-hedging (realized and unrealized) losses	**29**	22	(e, j)
Vacation pay	**91**	88	(f, j)
Building lease	**31**	37	(g, j)
Cancelled construction projects	**67**	70	(h)
Remaining net book value of retired units	**25**	28	(i)
Storm damage reserves	**98**	37	(c)
Other regulatory assets	**63**	49	(c)
Other cost of removal obligations	**(60)**	(58)	(b)
Deferred income tax credits	**(106)**	(112)	(b, j)
Other regulatory liabilities	**(7)**	(6)	(e, j)
Total regulatory assets (liabilities), net	**$ 2,529**	$ 1,886	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 13 years . See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years . Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2014, other cost of removal obligations included $29 million that will be amortized over the remaining two -year period of January 2015 through December 2016 in accordance with the Company's 2013 ARP.

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding eight years .

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 38 years .

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered through the Company's fuel cost recovery mechanism.

(f) Recorded as earned by employees and recovered as paid, generally within one year . This includes both vacation and banked holiday pay.

(g) See Note 6 under "Capital Leases." Recovered over the remaining life of the building through 2020.

(h) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(i) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2022.

(j) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel. See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. State ITCs are recognized in the period in which the credits are claimed on the state income tax return. A portion of the ITCs available to reduce income taxes payable was not utilized currently and will be carried forward and utilized in future years.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the cost of equity and debt funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2014	2013
	(in millions)	
Generation	**$ 15,201**	$ 14,872
Transmission	**5,086**	4,859
Distribution	**8,913**	8,620
General	**1,855**	1,753
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 31,083**	$ 30,132

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.7% in 2014 , 3.0% in 2013 , and 2.9% in 2012 . Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $14 million is being amortized annually over the three years ending December 31, 2016.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The ARO liability relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, as well as various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the AROs included in the balance sheets are as follows:

	2014	2013
	(in millions)	
Balance at beginning of year	**$ 1,222**	$ 1,105
Liabilities incurred	**9**	2
Liabilities settled	**(12)**	(13)
Accretion	**53**	55
Cash flow revisions	**(17)**	73
Balance at end of year	**$ 1,255**	$ 1,222

The 2014 decrease in cash flow revisions is primarily related to settled AROs for asbestos remediation. The 2013 increase in cash flow revisions is related to updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units and revisions to the nuclear decommissioning AROs based on the latest decommissioning study.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million . The Company has previously recorded AROs associated with ash ponds of $500 million , or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2014 and 2013 , approximately $51 million and $32 million , respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $52 million and $33 million at December 31, 2014 and 2013 , respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2014 , investment securities in the Funds totaled $789 million , consisting of equity securities of $303 million , debt securities of $475 million , and $11 million of other securities. At December 31, 2013 , investment securities in the Funds totaled $751 million , consisting of equity securities of $330 million , debt securities of $397 million , and $24 million of other securities. These amounts include the investment securities pledged to creditors and collateral received, and exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $669 million , $705 million , and $850 million in 2014 , 2013 , and 2012 , respectively, all of which were reinvested. For 2014 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million , of which an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014 . For 2013 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $61 million , of which $34 million related to unrealized gains on securities held in the Funds at December 31, 2013 . For 2012 , fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $67 million , of which $25 million related to unrealized losses on securities held in the Funds at December 31, 2012 . While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

NOTES (continued)
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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 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

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)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in millions)		
Assets:				
Domestic equity*	$ 506	$ 296	$ —	$ 802
International equity*	389	359	—	748
Fixed income:				
U.S. Treasury, government, and agency bonds	—	212	—	212
Mortgage- and asset-backed securities	—	55	—	55
Corporate bonds	—	346	—	346
Pooled funds	—	166	—	166
Cash equivalents and other	—	79	—	79
Real estate investments	92	—	353	445
Private equity	—	—	202	202
Total	$ 987	$ 1,513	$ 555	$ 3,055
Liabilities:				
Derivatives	$ —	$ (1)	$ —	$ (1)
Total	$ 987	$ 1,512	$ 555	$ 3,054

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014 Real Estate Investments	**2014** Private Equity	2013 Real Estate Investments	2013 Private Equity
		(in millions)		
Beginning balance	**$ 353**	**$ 202**	$ 299	$ 211
Actual return on investments:				
Related to investments held at year end	**23**	**15**	25	3
Related to investments sold during the year	**12**	**(6)**	10	17
Total return on investments	**35**	**9**	35	20
Purchases, sales, and settlements	**3**	**(12)**	19	(29)
Ending balance	**$ 391**	**$ 199**	$ 353	$ 202

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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	**2014** Private Equity	2013 Real Estate Investments	2013 Private Equity
	(in millions)			
Beginning balance	**$ 11**	**$ 6**	$ 10	$ 7
Actual return on investments:				
Related to investments held at year end	**1**	**—**	1	—
Related to investments sold during the year	**—**	**—**	—	—
Total return on investments	**1**	**—**	1	—
Purchases, sales, and settlements	**—**	**—**	—	(1)
Ending balance	**$ 12**	**$ 6**	$ 11	$ 6

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014 , 2013 , and 2012 were $25 million , $24 million , and $24 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

The Company and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, the Company filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified the Company in 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, the Company, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. In February 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted the Company's summary judgment motion, ruling that the Company has no liability in the private action. In May 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

As a result of its first lawsuit, the Company recovered approximately $27 million , based on its ownership interests, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. The proceeds were received in 2012 and credited to the Company accounts where the original costs were charged and were used to reduce rate base, fuel, and cost of service for the benefit of customers.

On December 12, 2014, the Court of Federal Claims entered a judgment in favor of the Company in its second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. The Company was awarded approximately $18 million , based on its ownership interests. No amounts have been recognized in the financial statements as of December 31, 2014 . The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.

On March 4, 2014, the Company filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2014 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on the Company's net income is expected as a significant portion of any damage amounts collected from the government is expected to be credited to the Company accounts where the original costs were charged and used to reduce rate base, fuel, and cost of service for the benefit of customers.

On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities at the plants can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Rate Plans

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million ; (2) ECCR tariff by approximately $25 million ; (3) Demand-Side Management (DSM) tariffs by approximately $1 million ; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million , for a total increase in base revenues of approximately $110 million .

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million ;
- DSM tariffs by approximately $3 million ; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

Under the 2013 ARP, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00% . Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case. In 2014, the Company's retail ROE exceeded 12.00% , and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (2011 IRP Update) to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) were also approved and will be effective by April 16, 2016, based on a one -year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in the Company's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million . The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC in February 2013, requiring it to use options and hedges within a 24 -month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

The Company's under recovered fuel balance totaled approximately $199 million at December 31, 2014 and is included in current assets and other deferred charges and assets. At December 31, 2013 , the Company's over recovered fuel balance totaled approximately $58 million and was included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million . Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7% .

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million , $35 million , $50 million , and $60 million , effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle Owners and the Contractor began negotiations regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million . The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. The Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. The Company's eighth VCM report filed in February 2013 requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion .

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18 -month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18 -month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18 -month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion .

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion .

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that ongoing challenges with Contractor performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

Additional claims by the Contractor or the Company (on behalf of the Vogtle Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time.

Nuclear Waste Fund Fee

In November 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014. On June 17, 2014, the Georgia PSC approved the Company's request to credit customers the portion of fuel cost related to the nuclear waste fund fee. The nuclear waste fund rider to the Company's fuel tariffs became effective July 1, 2014.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $84 million in 2014 , $91 million in 2013 , and $107 million in 2012 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Duke Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Duke Energy Florida, Inc.

At December 31, 2014 , the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$ 3,420	$ 2,059	$ 46
Plant Hatch (nuclear)	50.1	1,117	559	66
Plant Wansley (coal)	53.5	856	278	15
Plant Scherer (coal)				
Units 1 and 2	8.4	254	83	1
Unit 3	75.0	1,172	417	10
Rocky Mountain (pumped storage)	25.4	182	124	2
Intercession City (combustion-turbine)	33.3	14	5	—

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

The Company also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in millions)	
Federal –			
Current	**$ 295**	$ 277	$ 273
Deferred	**366**	374	370
	661	651	643
State –			
Current	**82**	(30)	38
Deferred	**(14)**	102	7
	68	72	45
Total	**$ 729**	$ 723	$ 688

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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 . A t December 31, 2014, the Company had no bank term loans outstanding.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility will be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion .

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375% .

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion . The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million , which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million . The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. The Company also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume the Company's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company's ownership interest in Plant Vogtle Units 3 and 4.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2014 and 2013, the Company had a capital lease asset for its corporate headquarters building of $61 million , with accumulated depreciation at December 31, 2014 and 2013 of $21 million and $ 16 million , respectively. At December 31, 2014 and 2013 , the capitalized lease obligation was $40 million and $45 million , respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented. See Note 7 under "Fuel and Purchased Power Agreements" for additional information on capital lease PPAs that become effective in 2015.

Assets Subject to Lien

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of the Company that are secured by a first priority lien on (i) the Company’s 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

See "Capital Leases" above for information regarding certain assets held under capital leases.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2014 , committed credit arrangements with banks were as follows:

Expires [a]			
2016	**2018**	**Total**	**Unused**
	(in millions)		
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2015 or 2017.

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. All of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/_4$ of 1% for the Company.

The bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.

A portion of the $1.7 billion unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $865 million . In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

The Company had $156 million and $1.0 billion of short-term debt outstanding at December 31, 2014 and 2013, respectively. Details of short-term borrowings outstanding were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014:		
Commercial paper	$ 156	0.3%
December 31, 2013:		
Commercial paper	$ 647	0.2%
Short-term bank debt	400	0.9%
Total	$ 1,047	0.5%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $2.5 billion , $2.3 billion , and $2.1 billion , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Unit 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $19 million , $27 million , and $50 million in 2014, 2013, and 2012, respectively.

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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) a re estimated and included in total minimum lease payments.

(2) Amount necessary to reduce minimum lease payments to present value calculated at the Company's incremental borrowing rate at the inception of the leases.

(3) Once service commences under the PPAs beginning in 2015, the Company will recognize capital lease assets and capital lease obligations totaling $149 million , being the lesser of the estimated fair value of the lease property or the present value of the net minimum lease payments.

(4) A total of $1.1 billion of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $28 million for 2014 , $32 million for 2013 , and $34 million for 2012 . The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
		(in millions)	
2015	$ 18	$ 7	$ 25
2016	13	7	20
2017	9	7	16
2018	4	6	10
2019	1	4	5
2020 and thereafter	3	11	14
Total	$ 48	$ 42	$ 90

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million . At the termination of the leases, the lessee may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019 and also $100 million of senior notes issued in November 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, in December 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years . The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million .

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014 , there were approximately 1,000 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 2,034,150 shares, 1,509,662 shares, and 1,269,725 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20 , $2.93 , and $3.39 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014 , 2013 , and 2012 was $19 million , $16 million , and $34 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million , $6 million , and $13 million for the years ended December 31, 2014 , 2013 , and 2012 , respectively. As of December 31, 2014 , the aggregate intrinsic value for the options outstanding and options exercisable was $73 million and $51 million , respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three -year performance period which equates to the requisite service period. Employees that retire prior to the end of the three -year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three -year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 176,224 , 161,240 , and 152,812 , respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54 , $40.50 , and $41.99 , respectively.

The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014 , 2013 , and 2012 , total compensation cost for performance share units recognized in income was $6 million annually, with the related tax benefit of $2 million annually also recognized in income. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014 , there was $7 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months .

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million , per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years . The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. On April 1, 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks , with a maximum per occurrence per unit limit of $490 million . After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years . The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $72 million .

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12 -month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

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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.

As of December 31, 2013 , assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 5	$ —	$ 5
Nuclear decommissioning trusts: [(a)]				
Domestic equity	197	1	—	198
Foreign equity	—	131	—	131
U.S. Treasury and government agency securities	—	79	—	79
Municipal bonds	—	64	—	64
Corporate bonds	—	140	—	140
Mortgage and asset backed securities	—	114	—	114
Other	—	24	—	24
Total	$ 197	$ 558	$ —	$ 755
Liabilities:				
Energy-related derivatives	$ —	$ 21	$ —	$ 21

(a) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases and the lending pool. See Note 1 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally, implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgment, are also obtained when available.

As of December 31, 2014 and 2013 , the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value		Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in millions)*				
Nuclear decommissioning trusts:					
Foreign equity fund	$	121	None	Monthly	5 days
Other — commingled funds		8	None	Daily	Not applicable
Other — money market funds		11	None	Daily	Not applicable
As of December 31, 2013:					
Nuclear decommissioning trusts:					
Foreign equity fund	$	131	None	Daily	5 days
Corporate bonds — commingled funds		8	None	Daily	Not applicable
Other — commingled funds		24	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities, depositary receipts, including American depositary receipts, European depositary receipts, and global depositary receipts; and rights and warrants to buy common stocks. The Company may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million , provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The other-commingled funds and other-money market funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high quality, short-term, liquid debt securities. The funds represent the cash collateral received under the Funds' managers' securities lending program and/or the excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the funds. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2014 and 2013 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount		Fair Value	
	(in millions)			
Long-term debt:				
2014	**$**	**9,797**	**$**	**10,552**
2013	$	8,593	$	8,782

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates offered to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014 , the net volume of energy-related derivative contracts for natural gas positions totaled 46 million mmBtu, all of which expire by 2017 , which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2014 , the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 350	3-month LIBOR	2.57%	May 2025	$ (6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair value hedges of existing debt					
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$ 1,600				$ (9)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses related to interest rate derivative settlements of cash flow hedges that are expected to be amortized into earnings through 2037 .

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013 , the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 6**	$ 3	Liabilities from risk management activities	**$ 23**	$ 13
	Other deferred charges and assets	**1**	2	Other deferred credits and liabilities	**4**	8
Total derivatives designated as hedging instruments for regulatory purposes		**$ 7**	$ 5		**$ 27**	$ 21
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	**$ 5**	$ —	Liabilities from risk management activities	**$ 9**	$ —
	Other deferred charges and assets	**1**	—	Other deferred credits and liabilities	**5**	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 6**	$ —		**$ 14**	$ —
Total		**$ 13**	$ 5		**$ 41**	$ 21

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value				
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 7**	$ 5	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 27**	$ 21
Gross amounts not offset in the Balance Sheet [(b)]	**(7)**	(5)	Gross amounts not offset in the Balance Sheet [(b)]	**(7)**	(5)
Net energy-related derivative assets	**$ —**	$ —	**Net energy-related derivative liabilities**	**$ 20**	$ 16
Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 6**	$ —	Interest rate derivatives presented in the Balance Sheet [(a)]	**$ 14**	$ —
Gross amounts not offset in the Balance Sheet [(b)]	**(6)**	—	Gross amounts not offset in the Balance Sheet [(b)]	**(6)**	—
Net interest rate derivative assets	**$ —**	$ —	**Net interest rate derivative liabilities**	**$ 8**	$ —

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

NOTES (continued)
Georgia Power Company 2014 Annual Report

At December 31, 2014 and 2013 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (23)**	$ (13)	Other regulatory liabilities, current	**$ 6**	$ 3
	Other regulatory assets, deferred	**(4)**	(8)	Other deferred credits and liabilities	**1**	2
Total energy-related derivative gains (losses)		**$ (27)**	$ (21)		**$ 7**	$ 5

For the year ended December 31, 2014 , the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the statement of income was immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statement of income was offset by changes to the carrying value of the long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

The pre-tax effects of interest rate derivatives designated as cash flow hedging instruments include $8 million of losses recognized in OCI for the year ended December 31, 2014 and amounts reclassified from accumulated OCI into earnings that were immaterial for all years presented.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014 , the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014 , the fair value of derivative liabilities with contingent features was $4 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

NOTES (continued)
Georgia 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	**$ 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
Georgia Power Company 2014 Annual Report

		2014		2013		2012		2011		2010
Operating Revenues (in millions)	**$**	**8,988**	$	8,274	$	7,998	$	8,800	$	8,349
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$**	**1,225**	$	1,174	$	1,168	$	1,145	$	950
Cash Dividends on Common Stock (in millions)	**$**	**954**	$	907	$	983	$	1,096	$	820
Return on Average Common Equity (percent)		**12.24**		12.45		12.76		12.89		11.42
Total Assets (in millions)	**$**	**31,030**	$	28,907	$	28,803	$	27,151	$	25,914
Gross Property Additions (in millions)	**$**	**2,146**	$	1,906	$	1,838	$	1,981	$	2,401
Capitalization (in millions):										
Common stock equity	**$**	**10,421**	$	9,591	$	9,273	$	9,023	$	8,741
Preferred and preference stock		**266**		266		266		266		266
Long-term debt		**8,683**		8,633		7,994		8,018		7,931
Total (excluding amounts due within one year)	**$**	**19,370**	$	18,490	$	17,533	$	17,307	$	16,938
Capitalization Ratios (percent):										
Common stock equity		**53.8**		51.9		52.9		52.1		51.6
Preferred and preference stock		**1.4**		1.4		1.5		1.5		1.6
Long-term debt		**44.8**		46.7		45.6		46.4		46.8
Total (excluding amounts due within one year)		**100.0**		100.0		100.0		100.0		100.0
Customers (year-end):										
Residential		**2,102,673**		2,080,358		2,062,040		2,047,390		2,049,770
Commercial*		**301,246**		298,420		296,397		295,288		295,347
Industrial*		**9,132**		9,136		9,143		9,134		8,929
Other		**9,003**		8,623		7,724		7,521		7,309
Total		**2,422,054**		2,396,537		2,375,304		2,359,333		2,361,355
Employees (year-end)		**7,909**		7,886		8,094		8,310		8,330

* A reclassification of customers from commercial to industrial is reflected for years 2010-2013 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

SELECTED FINANCIAL AND OPERATING DATA 2010 - 2014 (continued)
Georgia Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	**$ 3,350**	$ 3,058	$ 2,986	$ 3,241	$ 3,072
Commercial	**3,271**	3,077	2,965	3,217	3,011
Industrial	**1,525**	1,391	1,322	1,547	1,441
Other	**94**	94	89	94	84
Total retail	**8,240**	7,620	7,362	8,099	7,608
Wholesale — non-affiliates	**335**	281	281	341	380
Wholesale — affiliates	**42**	20	20	32	53
Total revenues from sales of electricity	**8,617**	7,921	7,663	8,472	8,041
Other revenues	**371**	353	335	328	308
Total	**$ 8,988**	$ 8,274	$ 7,998	$ 8,800	$ 8,349
Kilowatt-Hour Sales (in millions):					
Residential	**27,132**	25,479	25,742	27,223	29,433
Commercial	**32,426**	31,984	32,270	32,900	33,855
Industrial	**23,549**	23,087	23,089	23,519	23,209
Other	**633**	630	641	657	663
Total retail	**83,740**	81,180	81,742	84,299	87,160
Wholesale — non-affiliates	**4,323**	3,029	2,934	3,904	4,662
Wholesale — affiliates	**1,117**	496	600	626	1,000
Total	**89,180**	84,705	85,276	88,829	92,822
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.35**	12.00	11.60	11.91	10.44
Commercial	**10.09**	9.62	9.19	9.78	8.89
Industrial	**6.48**	6.03	5.73	6.58	6.21
Total retail	**9.84**	9.39	9.01	9.61	8.73
Wholesale	**6.93**	8.54	8.52	8.23	7.65
Total sales	**9.66**	9.35	8.99	9.54	8.66
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,969**	12,293	12,509	13,288	14,367
Residential Average Annual Revenue Per Customer	**$ 1,605**	$ 1,475	$ 1,451	$ 1,582	$ 1,499
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**17,593**	17,586	17,984	16,588	15,992
Maximum Peak-Hour Demand (megawatts):					
Winter	**16,308**	12,767	14,104	14,800	15,614
Summer	**15,777**	15,228	16,440	16,941	17,152
Annual Load Factor (percent)	**61.2**	63.5	59.1	59.5	60.9
Plant Availability (percent)*:					
Fossil-steam	**86.3**	87.1	90.3	88.6	88.6
Nuclear	**90.8**	91.8	94.1	92.2	94.0
Source of Energy Supply (percent):					
Coal	**30.9**	26.4	26.6	44.4	51.8
Nuclear	**16.7**	17.7	18.3	16.6	16.4
Hydro	**1.3**	2.0	0.7	1.1	1.4
Oil and gas	**26.3**	29.6	22.0	8.9	8.0
Purchased power —					
From non-affiliates	**3.8**	3.3	6.8	6.1	5.2
From affiliates	**21.0**	21.0	25.6	22.9	17.2

Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

GULF POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2014 Annual Report

The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014 .

/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
President and Chief Executive Officer

/s/ Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer

March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

**To the Board of Directors of
Gulf Power Company**

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-307 to II-345) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2014 and 2013 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2014 Annual Report

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

In December 2013, the Florida PSC voted to approve the settlement agreement (Settlement Agreement) among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017; and (4) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" herein for additional details of the Settlement Agreement.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance, which the Company achieved in 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2014 Peak Season EFOR of 0.98% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2014 was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2014 net income after dividends on preference stock was $140.2 million, representing a $15.8 million, or 12.7%, increase over the previous year. The increase was primarily due to higher retail revenues, partially offset by higher other operations and maintenance expenses as compared to the corresponding period in 2013.

In 2013, net income after dividends on preference stock was $124.4 million, representing a $1.5 million, or 1.2%, decrease from the previous year. The decrease was primarily due to an increase in depreciation and dividends on preference stock, partially offset by decreases in other operations and maintenance expenses and interest expense as compared to the corresponding period in 2012.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2014 Annual Report

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	**2014**	2013
		(in millions)	
Operating revenues	**$ 1,590.5**	**$ 150.2**	$ 0.6
Fuel	**604.6**	**71.8**	(12.1)
Purchased power	**107.2**	**21.9**	11.2
Other operations and maintenance	**341.2**	**31.4**	(4.3)
Depreciation and amortization	**145.0**	**(4.0)**	8.0
Taxes other than income taxes	**111.2**	**12.8**	1.0
Total operating expenses	**1,309.2**	**133.9**	3.8
Operating income	**281.3**	**16.3**	(3.2)
Total other income and (expense)	**(44.0)**	**9.2**	3.7
Income taxes	**88.1**	**8.4**	0.5
Net income	**149.2**	**17.1**	—
Dividends on preference stock	**9.0**	**1.3**	1.5
Net income after dividends on preference stock	**$ 140.2**	**$ 15.8**	$ (1.5)

Operating Revenues

Operating revenues for 2014 were $1.59 billion, reflecting an increase of $150.2 million from 2013. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	**$ 1,170.0**	$ 1,144.5
Estimated change resulting from –		
Rates and pricing	**47.1**	0.1
Sales growth (decline)	**8.2**	(1.4)
Weather	**9.4**	(0.3)
Fuel and other cost recovery	**31.8**	27.1
Retail — current year	**1,266.5**	1,170.0
Wholesale revenues –		
Non-affiliates	**129.2**	109.4
Affiliates	**130.1**	99.6
Total wholesale revenues	**259.3**	209.0
Other operating revenues	**64.7**	61.3
Total operating revenues	**$ 1,590.5**	$ 1,440.3
Percent change	**10.4%**	—%

In 2014, retail revenues increased $96.5 million, or 8.3%, when compared to 2013 primarily as a result of higher fuel cost recovery revenues and higher revenues resulting from an increase in retail base rates effective January 2014, as approved by the Florida PSC. In 2013, retail revenues increased $25.5 million, or 2.2%, when compared to 2012 primarily as a result of higher fuel revenues and energy conservation cost recovery revenues. The increase in fuel revenues was partially offset by a payment received during 2013 pursuant to the resolution of a coal contract dispute. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2014 Annual Report

In 2014, revenues associated with changes in rates and pricing included higher revenues due to an increase in retail base rates and revenues associated with higher rates under the Company's environmental cost recovery clause. In 2013, revenues associated with changes in rates and pricing were relatively flat as a result of higher revenues due to increases in retail base rates, partially offset by lower rates under the Company's energy conservation cost recovery clause and the environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2014	2013	2012
		(in millions)	
Capacity and other	**$ 65.1**	$ 64.0	$ 68.2
Energy	**64.1**	45.4	38.7
Total non-affiliated	**$ 129.2**	$ 109.4	$ 106.9

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information.

In 2014, wholesale revenues from sales to non-affiliates increased $19.8 million, or 18.1%, as compared to the prior year primarily due to a 43.7% increase in KWH sales as a result of lower-priced energy supply alternatives from the Southern Company system's resources and fewer planned outages at Plant Scherer Unit 3 partially offset by a 1.9% decrease in the price of energy sold to non-affiliates due to the lower cost of fuel per KWH generated. In 2013, wholesale revenues from sales to non-affiliates increased $2.5 million, or 2.3%, as compared to the prior year primarily due to an 18.9% increase in KWH sales as a result of more energy scheduled by wholesale customers to serve their loads. This increase was partially offset by a 6.2% decrease in capacity revenues reflecting contractual reductions for changes in environmental costs.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2014, wholesale revenues from sales to affiliates increased $30.5 million, or 30.7%, as compared to the prior year primarily due to a 24.5% increase in the price of energy sold to affiliates due to higher marginal generation costs and a 5.0% increase in KWH sales as a result of an increase of the Company's generation dispatched to serve affiliated companies' higher weather-related energy demand primarily in the first and third quarters of 2014. In 2013, wholesale revenues from sales to affiliates decreased $24.1 million, or 19.5%, as compared to the prior year primarily due to lower energy revenues related to a 28.4% decrease in KWH sales that resulted from less Company generation being dispatched to serve affiliated companies' demand. This decrease in 2013 was partially offset by a 12.7% increase in the price of energy sold to affiliates in 2013.

Other operating revenues increased $3.4 million, or 5.5%, in 2014 as compared to the prior year primarily due to a $4.5 million increase in franchise fees due to increased retail revenues, partially offset by a $2.3 million decrease in revenues from other energy services. In 2013, other operating revenues decreased $3.4 million, or 5.3%, as compared to the prior year primarily due to a $5.4 million decrease in revenues from other energy services, partially offset by a $1.9 million increase in transmission

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revenues. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	**2014**	2013	**2014**	2013
	(in millions)				
Residential	**5,363**	**5.4%**	0.7 %	**1.3%**	0.5 %
Commercial	**3,838**	**0.7**	(1.3)	**0.1**	(0.4)
Industrial	**1,849**	**8.8**	(1.4)	**8.8**	(1.4)
Other	**25**	**20.5**	(17.1)	**20.5**	(17.1)
Total retail	**11,075**	**4.3**	(0.4)	**2.1%**	(0.2)%
Wholesale					
Non-affiliates	**1,670**	**43.7**	18.9		
Affiliates	**3,284**	**5.0**	(28.4)		
Total wholesale	**4,954**	**15.5**	(19.8)		
Total energy sales	**16,029**	**7.5%**	(6.9)%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth. Residential KWH sales increased in 2013 compared to 2012 primarily due to customer growth.

Commercial KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth, partially offset by a decline in weather-adjusted use per customer. Commercial KWH sales decreased in 2013 compared to 2012 primarily due to milder weather in 2013 compared to 2012 and a decline in weather-adjusted use per customer, partially offset by customer growth.

Industrial KWH sales increased in 2014 compared to 2013 primarily due to decreased customer co-generation and changes in customers' operations. Industrial KWH sales decreased in 2013 compared to 2012 primarily due to changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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Details of the Company's generation and purchased power were as follows:

	2014	2013	2012
Total generation *(millions of KWHs)*	**11,109**	9,216	9,648
Total purchased power *(millions of KWHs)*	**5,547**	6,298	6,952
Sources of generation *(percent)* –			
Coal	**67**	61	60
Gas	**33**	39	40
Cost of fuel, generated *(cents per net KWH)* –			
Coal [(a)]	**4.03**	4.12	4.42
Gas	**3.93**	3.95	3.96
Average cost of fuel, generated *(cents per net KWH)* [(a)]	**3.99**	4.05	4.23
Average cost of purchased power *(cents per net KWH)* [(b)]	**4.83**	3.88	3.03

(a) 2013 cost of coal includes the effect of a payment received pursuant to the resolution of a coal contract dispute.

(b) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2014, total fuel and purchased power expenses were $711.8 million, an increase of $93.7 million, or 15.2%, from the prior year costs. Total fuel and purchased power expenses for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the higher volume of KWHs generated and purchased increased expenses $54.9 million primarily due to increased Company owned generation dispatched to serve higher Southern Company system demand as a result of colder weather in the first quarter and warmer weather in the third quarter 2014. The increased expenses also included an $18.3 million increase due to a higher average cost of fuel and purchased power.

In 2013, total fuel and purchased power expenses were $618.1 million, a decrease of $0.9 million, or 0.2%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $37.3 million decrease in the volume of KWHs generated and purchased, partially offset by a $36.4 million increase in the average cost of fuel and purchased power which included a payment received during 2013 pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel and purchased power increased $57.0 million.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost, purchased power capacity recovery clauses, and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $604.6 million in 2014, an increase of $71.8 million, or 13.5%, from the prior year costs. The increase was primarily due to a 20.5% higher volume of KWHs generated primarily due to increased generation dispatched to serve higher Southern Company system loads due to colder weather in the first quarter 2014 and warmer weather in the third quarter 2014. The fuel expense for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated decreased 6.8%. In 2013, fuel expense was $532.8 million, a decrease of $12.1 million, or 2.2%, from the prior year costs. The decrease was primarily due to a 4.3% decrease in the average cost of fuel per KWH generated which included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated increased 1.2%.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $82.0 million in 2014, an increase of $29.6 million, or 56.3%, from the prior year. The increase was due to a 37.3% increase in the average cost per KWH purchased, which included a $28.4 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA. This increase was partially offset by a 16.3% decrease in the volume of KWHs purchased due to colder regional weather conditions in the first quarter 2014 which limited the availability of market resources. In 2013, purchased power expense from non-affiliates was $52.4 million, an increase of $1.0 million, or 2.0%, from the prior year. The increase was due to a 31.5% increase in the average cost per KWH purchased, partially offset by a 13.8% decrease in the volume of KWHs purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $25.2 million in 2014, a decrease of $7.7 million, or 23.1%, from the prior year. The decrease was primarily due to a 43.3% decrease in the average cost per KWH purchased, which included a $13.5 million reduction in capacity costs primarily associated with the expiration of an existing PPA. This decrease was partially offset by a 33.2% increase in the volume of KWHs purchased primarily due to higher planned outages for the Company's generating units in the fourth quarter 2014. In 2013, purchased power expense from affiliates was $32.9 million, an increase of $10.2 million, or 44.9%, from the prior year. The increase was primarily due to a 93.4% increase in the volume of KWHs purchased, partially offset by a 30.2% decrease in the average cost per KWH purchased.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $31.4 million, or 10.1%, compared to the prior year primarily due to increases in routine and planned maintenance expenses at generation, transmission and distribution facilities.

In 2013, other operations and maintenance expenses decreased $4.3 million, or 1.4%, compared to the prior year primarily due to decreases of $14.4 million in routine and planned maintenance expenses at generation facilities related to decreases in scheduled outages and cost containment efforts in 2013 and $4.9 million in other energy services expenses, partially offset by increases of $5.1 million in pension and other benefit-related expenses, $4.9 million in transmission service related to a third party PPA, $2.2 million in distribution system maintenance primarily due to increased vegetation management and $2.1 million in marketing incentive programs. Expenses from other energy services did not have a significant impact on earnings since they were generally offset by associated revenues. Expenses from transmission service did not have a significant impact on earnings since this expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. Expenses from marketing incentive programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses," and Notes 1 and 3 to the financial statements under "Affiliate Transactions" and "Cost Recovery Clauses," respectively, for additional information.

Depreciation and Amortization

Depreciation and amortization decreased $4.0 million, or 2.7%, in 2014 compared to the prior year. As authorized by the Florida PSC in the Settlement Agreement, the Company recorded an $8.4 million reduction in depreciation expense in 2014. This decrease was partially offset by increases of $4.4 million in depreciation and amortization primarily attributable to property additions at generation, transmission, and distribution facilities. In 2013, depreciation and amortization increased $8.0 million, or 5.7%, compared to the prior year primarily attributable to equipment replacements completed on Plant Crist Unit 7 and other additions to transmission and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12.8 million, or 13.0%, in 2014 compared to the prior year primarily due to increases of $4.4 million in franchise fees and $4.0 million in gross receipts taxes as a result of higher retail revenues as well as a $2.7 million increase in property taxes. In 2013, taxes other than income taxes increased $1.0 million, or 1.1%, compared to the prior year primarily due to a $2.8 million increase in property taxes, partially offset by decreases of $0.7 million in gross receipts taxes, $0.7 million in payroll taxes, and $0.4 million in franchise fees. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $5.6 million, or 86.4%, in 2014 compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities and transmission projects. In 2013, AFUDC equity increased $1.2 million, or 23.5%, compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $2.8 million, or 5.0%, in 2014 compared to the prior year primarily due to an increase in capitalization of AFUDC debt related to the construction of environmental control projects and lower interest rates on pollution control bonds, offset by increases in long term debt resulting from the issuance of additional senior notes in 2014. In 2013, interest expense, net of amounts capitalized decreased $4.2 million, or 7.0%, compared to the prior year primarily due to lower interest rates on pollution control bonds, senior notes, and customer deposits.

Income Taxes

Income taxes increased $8.4 million, or 10.5%, in 2014 compared to the prior year primarily due to higher pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in the Company's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

The Company's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that the Company serves the customer's capacity and energy requirements from other Company resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with the Company's co-ownership of a unit with Georgia Power at Plant Scherer and consist of both capacity and energy sales. Capacity revenues represent the majority of the Company's wholesale earnings. The Company currently has long-term sales agreements for 100% of the Company's ownership of that unit for 2015 and 41% for the next five years. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. The Company is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on the Company's earnings. In the event some portion of the Company's ownership in Plant Scherer is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. The full impact of any such regulatory or legislative changes cannot be determined at this time. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

Subsequent to December 31, 2014, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016. The plant will continue to operate and produce electricity with its other generating units on site. The cost to comply with environmental regulations imposed by the EPA led to the decision to close these units. The retirement of these units is not expected to have a material impact on the Company's financial statements. The Company expects to recover through its rates the remaining book value of the retired units and certain costs associated with the retirements; however, recovery will be considered by the Florida PSC in future rate proceedings. The net book value of these units at December 31, 2014 was approximately $80 million.

The Company has also determined it is not economical to add the environmental controls at Plant Scholz necessary to comply with the Mercury and Air Toxics Standards (MATS) rule and that coal-fired generation at Plant Scholz (92 MWs) will cease by April 2015. The plant is scheduled to be fully depreciated by April 2015.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Georgia Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the Company had invested approximately $1.8 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $227 million, $143 million, and $70 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $204 million from 2015 through 2017, with annual totals of approximately $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $1.4 billion in reducing and monitoring emissions pursuant to the Clean Air

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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 MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS . In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Florida, so future nonattainment designations in these areas are possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Florida, Georgia, and Mississippi) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

These proposed and final water quality regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Georgia, and Mississippi each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 8 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 10 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. The Company recognized an $8.4 million reduction in depreciation expense in 2014.

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

Income Tax Matters

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $25 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $65 million to $70 million for the 2015 tax year.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial position, results of operations, or cash flows.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high-quality fixed income securities with maturities that correspond to expected benefit payments.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $3.9 million and $0.1 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.6 million or less change in total annual benefit expense and a $22.0 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances and through equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $30.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $343.1 million in 2014, an increase of $13.4 million from 2013, primarily due to changes in cash flows related to clause recovery and a decrease in fossil fuel stock. This increase was partially offset by decreases in cash flows associated with pension, post-retirement and other employee benefits, and deferred income taxes.

In 2013, net cash provided from operating activities totaled $329.7 million, a decrease of $89.5 million from 2012, primarily due to decreases in deferred income taxes related to bonus depreciation and lower recovery of fuel costs which moved from an over recovered to an under recovered position. These decreases were partially offset by increases in cash flow related to reductions in fossil fuel stock.

Net cash used for investing activities totaled $357.7 million, $306.6 million, and $348.6 million for 2014, 2013, and 2012, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $360.9 million, $304.8 million, and $325.2 million for 2014, 2013, and 2012, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash provided from financing activities totaled $31.5 million for 2014. Net cash used for financing activities totaled $33.6 million and $55.8 million for 2013 and 2012, respectively. The $65.1 million increase in cash from financing activities in 2014 was primarily due to the issuance of long-term debt and common stock, partially offset by the payment of common stock dividends, the redemption of long-term debt and a decrease to notes payable. The decreases of cash used in 2013 and 2012 were primarily for the payment of common stock dividends and redemptions of long-term debt, partially offset by issuances of stock to Southern Company and issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2014 included increases of $231.3 million in property, plant, and equipment, primarily due to additions in generation, transmission, and distribution facilities, $211.4 million in long-term debt, $75.6 million in other regulatory assets, deferred, related to pension and other postretirement benefits, $55.7 million in other regulatory assets primarily related to an increase in contract hedges, $50.0 million in common stock issued to Southern Company, and $44.4 million in employee benefit obligations as a result of changes in the actuarial assumptions. Decreases included $75.0 million in securities due within one year.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.6% in 2014 and 44.9% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2014, the Company had approximately $38.6 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$80	$ 165	$30	$275	$275	$50	$—	$50	$30

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration.

Most of the unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $69.3 million. At December 31, 2014, the Company had $78.0 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014:					
Commercial paper	**$ 110**	**0.3%**	**$ 85**	**0.2%**	**$145**
December 31, 2013:					
Commercial paper	$ 136	0.2%	$ 92	0.2%	$173
Short-term bank debt	—	N/A	11	1.2%	125
Total	$ 136	0.2%	$ 103	0.3%	
December 31, 2012:					
Commercial paper	$ 124	0.3%	$ 69	0.3%	$124

(a) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash.

Financing Activities

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50.0 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program, and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 74
Below BBB- and/or Baa3	447

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2015 was .02%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $0.7 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (10)**	$ (23)
Contracts realized or settled	**(3)**	13
Current period changes [(a)]	**(59)**	—
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (72)**	$ (10)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**85**	87
Commodity – Natural gas options	**—**	2
Total hedge volume	**85**	89

The weighted average swap contract cost above market prices was approximately $0.80 per mmBtu as of December 31, 2014 and $0.12 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(72)	(37)	(33)	(2)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (72)	$ (37)	$ (33)	$ (2)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $263 million for 2015 , $186 million for 2016 , and $168 million for 2017 . Capital expenditures to comply with environmental statutes and regulations included in these amounts are estimated to be $127 million, $39 million, and $38 million for 2015 , 2016 , and 2017 , respectively. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts;

changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in thousands)		
Long-term debt [(a)] –					
Principal	$ —	$ 195,000	$ —	$ 1,183,955	$ 1,378,955
Interest	57,546	109,262	93,402	853,213	1,113,423
Financial derivative obligations [(b)]	36,934	32,938	2,563	—	72,435
Preference stock dividends [(c)]	9,003	18,006	18,006	—	45,015
Operating leases [(d)]	15,239	16,624	—	—	31,863
Unrecognized tax benefits [(e)]	46	—	—	—	46
Purchase commitments –					
Capital [(f)]	262,814	326,536	—	—	589,350
Fuel [(g)]	276,437	349,155	255,854	145,535	1,026,981
Purchased power [(h)]	92,395	183,929	182,929	315,331	774,584
Other [(i)]	16,498	20,616	15,820	43,145	96,079
Pension and other postretirement benefit plans [(j)]	4,716	10,061	—	—	14,777
Total	$ 771,628	$ 1,262,127	$ 568,574	$ 2,541,179	$ 5,143,508

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) Excludes a PPA accounted for as a lease and is included in purchased power.

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in Other. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(g) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.

(h) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

(i) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf 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 and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water , CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil action against the Company and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards ;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2014 Annual Report

- 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
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 1,266,540**	$ 1,170,000	$ 1,144,471
Wholesale revenues, non-affiliates	**129,151**	109,386	106,881
Wholesale revenues, affiliates	**130,107**	99,577	123,636
Other revenues	**64,684**	61,338	64,774
Total operating revenues	**1,590,482**	1,440,301	1,439,762
Operating Expenses:			
Fuel	**604,641**	532,791	544,936
Purchased power, non-affiliates	**81,993**	52,443	51,421
Purchased power, affiliates	**25,246**	32,835	22,665
Other operations and maintenance	**341,214**	309,865	314,195
Depreciation and amortization	**145,026**	149,009	141,038
Taxes other than income taxes	**111,147**	98,355	97,313
Total operating expenses	**1,309,267**	1,175,298	1,171,568
Operating Income	**281,215**	265,003	268,194
Other Income and (Expense):			
Allowance for equity funds used during construction	**12,021**	6,448	5,221
Interest income	**90**	369	1,408
Interest expense, net of amounts capitalized	**(53,234)**	(56,025)	(60,250)
Other income (expense), net	**(2,851)**	(3,994)	(3,227)
Total other income and (expense)	**(43,974)**	(53,202)	(56,848)
Earnings Before Income Taxes	**237,241**	211,801	211,346
Income taxes	**88,062**	79,668	79,211
Net Income	**149,179**	132,133	132,135
Dividends on Preference Stock	**9,003**	7,704	6,203
Net Income After Dividends on Preference Stock	**$ 140,176**	$ 124,429	$ 125,932

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Net Income	**$ 149,179**	$ 132,133	$ 132,135
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $234, $297, and $360, respectively	**372**	472	573
Total other comprehensive income (loss)	**372**	472	573
Comprehensive Income	**$ 149,551**	$ 132,605	$ 132,708

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014 , 2013 , and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income	$ **149,179**	$ 132,133	$ 132,135
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**152,670**	155,798	147,723
Deferred income taxes	**65,330**	77,069	174,305
Allowance for equity funds used during construction	**(12,021)**	(6,448)	(5,221)
Pension, postretirement, and other employee benefits	**(23,305)**	11,422	(8,109)
Stock based compensation expense	**1,928**	1,749	1,647
Other, net	**(1,233)**	5,865	4,518
Changes in certain current assets and liabilities —			
-Receivables	**(17,178)**	(49,051)	8,713
-Fossil fuel stock	**33,603**	19,468	(6,144)
-Materials and supplies	**(721)**	(1,570)	(3,035)
-Prepaid income taxes	**(19,179)**	15,526	355
-Other current assets	**(883)**	682	417
-Accounts payable	**8,279**	(6,964)	(5,195)
-Accrued taxes	**(1,924)**	(4,759)	(4,705)
-Accrued compensation	**11,237**	(3,309)	481
-Over recovered regulatory clause revenues	**—**	(17,092)	(10,858)
-Other current liabilities	**(2,704)**	(782)	(7,837)
Net cash provided from operating activities	**343,078**	329,737	419,190
Investing Activities:			
Property additions	**(348,305)**	(292,914)	(313,257)
Cost of removal net of salvage	**(12,932)**	(13,827)	(28,993)
Construction payables	**11,574**	6,796	1,161
Payments pursuant to long-term service agreements	**(8,012)**	(7,109)	(8,119)
Other investing activities	**(19)**	496	656
Net cash used for investing activities	**(357,694)**	(306,558)	(348,552)
Financing Activities:			
Increase (decrease) in notes payable, net	**(25,900)**	12,108	16,075
Proceeds —			
Common stock issued to parent	**50,000**	40,000	40,000
Capital contributions from parent company	**4,037**	2,987	2,106
Preference stock	**—**	50,000	—
Pollution control revenue bonds	**42,075**	63,000	13,000
Senior notes	**200,000**	90,000	100,000
Redemptions —			
Pollution control revenue bonds	**(29,075)**	(76,000)	(13,000)
Senior notes	**(75,000)**	(90,000)	(91,363)
Payment of preference stock dividends	**(9,003)**	(7,004)	(6,203)
Payment of common stock dividends	**(123,200)**	(115,400)	(115,800)
Other financing activities	**(2,457)**	(3,284)	(614)
Net cash provided from (used for) financing activities	**31,477**	(33,593)	(55,799)
Net Change in Cash and Cash Equivalents	**16,861**	(10,414)	14,839
Cash and Cash Equivalents at Beginning of Year	**21,753**	32,167	17,328
Cash and Cash Equivalents at End of Year	$ **38,614**	$ 21,753	$ 32,167

Supplemental Cash Flow Information:						
Cash paid (received) during the period for —						
Interest (net of $5,373, $3,421 and $2,500 capitalized, respectively)	**$**	**48,030**	$	53,401	$	58,255
Income taxes (net of refunds)		**44,125**		(10,727)		(96,639)
Noncash transactions — accrued property additions at year-end		**41,526**		31,546		27,369

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Assets	**2014**	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 38,614**	$ 21,753
Receivables —		
Customer accounts receivable	**73,000**	64,884
Unbilled revenues	**58,268**	57,282
Under recovered regulatory clause revenues	**57,153**	48,282
Other accounts and notes receivable	**8,145**	8,620
Affiliated companies	**9,867**	8,259
Accumulated provision for uncollectible accounts	**(2,087)**	(1,131)
Fossil fuel stock, at average cost	**101,447**	135,050
Materials and supplies, at average cost	**55,656**	54,935
Other regulatory assets, current	**74,242**	18,536
Prepaid expenses	**39,673**	33,186
Other current assets	**1,711**	6,120
Total current assets	**515,689**	455,776
Property, Plant, and Equipment:		
In service	**4,494,953**	4,363,664
Less accumulated provision for depreciation	**1,295,714**	1,211,336
Plant in service, net of depreciation	**3,199,239**	3,152,328
Construction work in progress	**465,033**	280,626
Total property, plant, and equipment	**3,664,272**	3,432,954
Other Property and Investments	**15,148**	15,314
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**55,931**	50,597
Prepaid pension costs	**—**	11,533
Other regulatory assets, deferred	**416,028**	340,415
Other deferred charges and assets	**41,191**	30,982
Total deferred charges and other assets	**513,150**	433,527
Total Assets	**$ 4,708,259**	$ 4,337,571

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	**2014**	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ —**	$ 75,000
Notes payable	**109,977**	135,878
Accounts payable —		
Affiliated	**87,397**	76,897
Other	**55,848**	47,038
Customer deposits	**35,094**	34,433
Accrued taxes —		
Accrued income taxes	**46**	45
Other accrued taxes	**9,201**	7,486
Accrued interest	**10,686**	10,272
Accrued compensation	**22,894**	11,657
Deferred capacity expense, current	**21,988**	—
Other regulatory liabilities, current	**566**	13,408
Liabilities from risk management activities	**36,934**	6,470
Other current liabilities	**22,386**	22,972
Total current liabilities	**413,017**	441,556
Long-Term Debt (See accompanying statements)	**1,369,594**	1,158,163
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**799,723**	734,355
Accumulated deferred investment tax credits	**2,783**	4,055
Employee benefit obligations	**120,752**	76,338
Deferred capacity expense	**163,077**	180,149
Other cost of removal obligations	**234,587**	228,148
Other regulatory liabilities, deferred	**48,556**	56,051
Other deferred credits and liabilities	**100,076**	77,126
Total deferred credits and other liabilities	**1,469,554**	1,356,222
Total Liabilities	**3,252,165**	2,955,941
Preference Stock (See accompanying statements)	**146,504**	146,504
Common Stockholder's Equity (See accompanying statements)	**1,309,590**	1,235,126
Total Liabilities and Stockholder's Equity	**$ 4,708,259**	$ 4,337,571
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

	2014	2013	**2014**	2013
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
4.90% due 2014	**—**	75,000		
5.30% due 2016	**110,000**	110,000		
5.90% due 2017	**85,000**	85,000		
3.10% to 5.75% due 2020-2051	**875,000**	675,000		
Total long-term notes payable	**1,070,000**	945,000		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	**239,625**	226,625		
Variable rates (0.02% to 0.04% at 1/1/15) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	295,955		
Unamortized debt discount	**(9,361)**	(7,792)		
Total long-term debt (annual interest requirement — $57.5 million)	**1,369,594**	1,233,163		
Less amount due within one year	**—**	75,000		
Long-term debt excluding amount due within one year	**1,369,594**	1,158,163	**48.5%**	45.6%
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	**53,886**	53,886		
— 6.45% preference stock — 450,000 shares (non-cumulative)	**44,112**	44,112		
— 5.60% preference stock — 500,000 shares (non-cumulative)	**48,506**	48,506		
Total preference stock (annual dividend requirement — $9.0 million)	**146,504**	146,504	**5.2**	5.8
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 2014: 5,442,717 shares				
— 2013: 4,942,717 shares	**483,060**	433,060		
Paid-in capital	**559,797**	552,681		
Retained earnings	**267,470**	250,494		
Accumulated other comprehensive loss	**(737)**	(1,109)		
Total common stockholder's equity	**1,309,590**	1,235,126	**46.3**	48.6
Total Capitalization	**$ 2,825,688**	$ 2,539,793	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014 , 2013 , and 2012
Gulf Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)			
Balance at December 31, 2011	4,143	$ 353,060	$ 542,709	$ 231,333	$ (2,154)	$ 1,124,948
Net income after dividends on preference stock	—	—	—	125,932	—	125,932
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	5,089	—	—	5,089
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(115,800)	—	(115,800)
Balance at December 31, 2012	4,543	393,060	547,798	241,465	(1,581)	1,180,742
Net income after dividends on preference stock	—	—	—	124,429	—	124,429
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	4,883	—	—	4,883
Other comprehensive income (loss)	—	—	—	—	472	472
Cash dividends on common stock	—	—	—	(115,400)	—	(115,400)
Balance at December 31, 2013	**4,943**	**433,060**	**552,681**	**250,494**	**(1,109)**	**1,235,126**
Net income after dividends on preference stock	**—**	**—**	**—**	**140,176**	**—**	**140,176**
Issuance of common stock	**500**	**50,000**	**—**	**—**	**—**	**50,000**
Capital contributions from parent company	**—**	**—**	**7,116**	**—**	**—**	**7,116**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**372**	**372**
Cash dividends on common stock	**—**	**—**	**—**	**(123,200)**	**—**	**(123,200)**
Balance at December 31, 2014	**5,443**	**$ 483,060**	**$ 559,797**	**$ 267,470**	**$ (737)**	**$ 1,309,590**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Gulf Power Company 2014 Annual Report

Index to the Notes to Financial Statements

NOTES (continued)
Gulf Power Company 2014 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Florida PSC. The Company follows GAAP in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $79.6 million , $78.4 million , and $95.9 million during 2014 , 2013 , and 2012 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8.7 million , $10.2 million , and $6.9 million and Mississippi Power $30.5 million , $16.5 million , and $21.1 million in 2014 , 2013 , and 2012 , respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a PPA with Southern Power for approximately 292 MWs annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $1.8 million , $14.2 million , and $14.7 million in 2014 , 2013 , and 2012 , respectively, and fuel costs associated with the PPA were $1.7 million , $0.8 million , and $2.6 million in 2014 , 2013 , and 2012 , respectively. These costs were approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company had an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $1.0 million in 2014 and $2.4 million in each of the years 2013 and 2012 for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $132.0 million for the entire project. These costs began in July 2012 and will continue through 2023.

The Company reimbursed Alabama Power $11.9 million , $7.9 million , and $3.0 million in 2014, 2013, and 2012, respectively, for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014 , 2013 , or 2012.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

NOTES (continued)
Gulf 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 thousands)		
Deferred income tax charges	**$ 53,234**	$ 47,573	(a)
Deferred income tax charges — Medicare subsidy	**3,024**	3,351	(b)
Asset retirement obligations	**(5,087)**	(6,089)	(a,j)
Other cost of removal obligations	**(242,997)**	(228,148)	(a)
Regulatory asset, offset to other cost of removal	**8,410**	—	(m)
Deferred income tax credits	**(3,872)**	(5,238)	(a)
Loss on reacquired debt	**15,991**	16,565	(c)
Vacation pay	**10,006**	9,521	(d,j)
Under recovered regulatory clause revenues	**52,619**	45,191	(e)
Property damage reserve	**(35,111)**	(35,380)	(f)
Fuel-hedging (realized and unrealized) losses	**73,474**	17,043	(g,j)
Fuel-hedging (realized and unrealized) gains	**(112)**	(6,962)	(g,j)
PPA charges	**185,065**	180,149	(j,k)
Other regulatory assets	**9,753**	12,772	(l)
Environmental remediation	**48,271**	50,384	(h,j)
Other regulatory liabilities	**(649)**	(8,804)	(f,j)
Retiree benefit plans, net	**147,625**	68,296	(i,j)
Total regulatory assets (liabilities), net	**$ 319,644**	$ 160,224	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years .

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years .

(d) Recorded as earned by employees and recovered as paid, generally within one year . This includes both vacation and banked holiday pay.

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year .

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years . Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years . See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Recovered over the life of the PPA for periods up to nine years.

(l) Comprised primarily of net book value of retired meters, deferred rate case expenses, and generation site evaluation costs. These costs are recorded and recovered or amortized as approved by the Florida PSC, generally over periods not exceeding eight years , or deferred pursuant to Florida statute while the Company continues to evaluate certain potential new generating projects.

(m) Recorded as authorized by the Florida PSC in a settlement agreement approved in December 2013. See Note 3 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.

The Company's property, plant, and equipment in service consisted of the following at December 31:

	2014	2013
	(in thousands)	
Generation	**$ 2,637,817**	$ 2,607,166
Transmission	**515,754**	473,378
Distribution	**1,156,872**	1,117,024
General	**182,734**	164,065
Plant acquisition adjustment	**1,776**	2,031
Total plant in service	**$ 4,494,953**	$ 4,363,664

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.6% in 2014 , 2013, and 2012 . Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized by the Florida PSC in the settlement agreement approved in December 2013 (Settlement Agreement), the Company is allowed to reduce depreciation expense and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the AROs included in the balance sheets are as follows:

	2014	2013
	(in thousands)	
Balance at beginning of year	**$ 16,184**	$ 16,055
Liabilities incurred	**—**	518
Liabilities settled	**(32)**	(1,913)
Accretion	**718**	751
Cash flow revisions	**(159)**	773
Balance at end of year	**$ 16,711**	$ 16,184

The 2014 cash flow revisions are associated with asbestos and ash ponds at the Company's steam generation facilities. The 2013 cash flow revisions are associated with asbestos and an unloading dock at its generation facilities.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million . The Company has previously recorded AROs associated with ash ponds of $6 million , or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 5.73% for 2014 , 6.26% for 2013 , and 6.72% for 2012 . AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 10.93% , 6.87% , and 5.36% for 2014 , 2013 , and 2012 , respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million , with a target level for the reserve between $48.0 million and $55.0 million . The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2014 , 2013 , and 2012 . As of December 31, 2014 and 2013 , the balance in the Company's property damage reserve totaled approximately $35.7 million and $35.4 million , respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. In December 2013, the Florida PSC approved the Settlement Agreement that, among other things, provides for recovery of costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00 / 1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional details of the Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2.0 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $4.0 million and $3.6 million at December 31, 2014 and 2013 , respectively. For 2014 , $1.6 million and $2.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2013 , $1.6 million and $2.0 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2014 or 2013 .

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014 .

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014 , the Company voluntarily contributed $30 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2015 , no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.88% , respectively, and an annual salary increase of 3.84% .

NOTES (continued)
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	2014	2013	2012
Discount rate:			
Pension plans	**4.18%**	5.02%	4.27%
Other postretirement benefit plans	**4.04**	4.86	4.06
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**8.08**	8.04	8.02

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million , respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2014 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$ 3,934	$ (3,334)
Service and interest costs	157	(133)

NOTES (continued)
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Pension Plans

The total accumulated benefit obligation for the pension plans was $438 million at December 31, 2014 and $353 million at December 31, 2013 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 395,328	$ 413,501
Service cost	10,181	11,128
Interest cost	19,433	17,321
Benefits paid	(15,635)	(14,831)
Actuarial (gain) loss	81,254	(31,791)
Balance at end of year	490,561	395,328
Change in plan assets		
Fair value of plan assets at beginning of year	385,639	350,260
Actual return on plan assets	33,512	49,076
Employer contributions	31,251	1,134
Benefits paid	(15,635)	(14,831)
Fair value of plan assets at end of year	434,767	385,639
Accrued liability	$ (55,794)	$ (9,689)

At December 31, 2014 , the projected benefit obligations for the qualified and non-qualified pension plans were $464 million and $26 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	$ —	$ 11,533
Other regulatory assets, deferred	145,815	75,280
Current liabilities, other	(1,307)	(1,183)
Employee benefit obligations	(54,487)	(20,039)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2015 .

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	$ 3,286	$ 4,401	$ 1,115
Net (gain) loss	142,529	70,879	9,281
Regulatory assets	$ 145,815	$ 75,280	

NOTES (continued)
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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	$ 75,280	$ 139,261
Net (gain) loss	76,209	(54,432)
Reclassification adjustments:		
Amortization of prior service costs	(1,115)	(1,164)
Amortization of net gain (loss)	(4,559)	(8,385)
Total reclassification adjustments	(5,674)	(9,549)
Total change	70,535	(63,981)
Ending balance	$ 145,815	$ 75,280

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	$ 10,181	$ 11,128	$ 9,101
Interest cost	19,433	17,321	17,199
Expected return on plan assets	(28,468)	(26,435)	(25,932)
Recognized net (gain) loss	4,559	8,385	3,913
Net amortization	1,115	1,164	1,262
Net periodic pension cost	$ 6,820	$ 11,563	$ 5,543

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2014 , estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2015	$ 22,002
2016	18,683
2017	19,950
2018	21,019
2019	22,229
2020 to 2024	129,877

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 68,579**	$ 75,395
Service cost	**1,163**	1,355
Interest cost	**3,235**	2,982
Benefits paid	**(4,061)**	(3,583)
Actuarial (gain) loss	**11,317**	(7,900)
Plan amendment	**(2,089)**	—
Retiree drug subsidy	**357**	330
Balance at end of year	**78,501**	68,579
Change in plan assets		
Fair value of plan assets at beginning of year	**17,474**	16,227
Actual return on plan assets	**1,578**	2,119
Employer contributions	**2,846**	2,381
Benefits paid	**(3,704)**	(3,253)
Fair value of plan assets at end of year	**18,194**	17,474
Accrued liability	**$ (60,307)**	$ (51,105)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	**$ 6,100**	$ —
Current liabilities, other	**(639)**	(687)
Other regulatory liabilities, deferred	**(4,290)**	(6,984)
Employee benefit obligations	**(59,668)**	(50,418)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2015 .

	2014	2013	**Estimated Amortization in 2015**
		(in thousands)	
Prior service cost	**$ (2,137)**	$ 138	**$ 25**
Net (gain) loss	**3,947**	(7,122)	**—**
Net regulatory assets (liabilities)	**$ 1,810**	$ (6,984)	

NOTES (continued)
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The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	$ **(6,984)**	$ 2,169
Net (gain) loss	**11,045**	(8,967)
Change in prior service costs	**(2,089)**	—
Reclassification adjustments:		
Amortization of prior service costs	**(186)**	(186)
Amortization of net gain (loss)	**24**	—
Total reclassification adjustments	**(162)**	(186)
Total change	**8,794**	(9,153)
Ending balance	$ **1,810**	$ (6,984)

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	$ **1,163**	$ 1,355	$ 1,167
Interest cost	**3,235**	2,982	3,367
Expected return on plan assets	**(1,306)**	(1,238)	(1,311)
Net amortization	**162**	186	379
Net periodic postretirement benefit cost	$ **3,254**	$ 3,285	$ 3,602

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2015	$ 4,694	$ (431)	$ 4,263
2016	4,982	(480)	4,502
2017	5,136	(535)	4,601
2018	5,300	(594)	4,706
2019	5,326	(660)	4,666
2020 to 2024	27,399	(3,430)	23,969

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**29%**	30%
International equity	24	**22**	24
Domestic fixed income	25	**29**	25
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2014 and 2013 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

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relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 76,460	$ 31,588	$ —	$ 108,048
International equity*	47,988	44,223	—	92,211
Fixed income:				
U.S. Treasury, government, and agency bonds	—	31,372	—	31,372
Mortgage- and asset-backed securities	—	8,438	—	8,438
Corporate bonds	—	50,931	—	50,931
Pooled funds	—	23,063	—	23,063
Cash equivalents and other	130	29,597	—	29,727
Real estate investments	13,154	—	50,281	63,435
Private equity	—	—	25,573	25,573
Total	$ 137,732	$ 219,212	$ 75,854	$ 432,798
Liabilities:				
Derivatives	$ (87)	$ —	$ —	$ (87)
Total	$ 137,645	$ 219,212	$ 75,854	$ 432,711

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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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 thousands)			
Assets:				
Domestic equity*	$ 63,269	$ 37,037	$ —	$ 100,306
International equity*	48,606	44,941	—	93,547
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,461	—	26,461
Mortgage- and asset-backed securities	—	6,873	—	6,873
Corporate bonds	—	43,222	—	43,222
Pooled funds	—	20,810	—	20,810
Cash equivalents and other	38	9,851	—	9,889
Real estate investments	11,493	—	44,139	55,632
Private equity	—	—	25,201	25,201
Total	$ 123,406	$ 189,195	$ 69,340	$ 381,941
Liabilities:				
Derivatives	$ —	$ (115)	$ —	$ (115)
Total	$ 123,406	$ 189,080	$ 69,340	$ 381,826

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in thousands)			
Beginning balance	**$ 44,139**	**$ 25,201**	$ 37,039	$ 26,129
Actual return on investments:				
Related to investments held at year end	**4,263**	**2,697**	3,357	376
Related to investments sold during the year	**1,488**	**(727)**	1,310	2,282
Total return on investments	**5,751**	**1,970**	4,667	2,658
Purchases, sales, and settlements	**391**	**(1,598)**	2,433	(3,586)
Ending balance	**$ 50,281**	**$ 25,573**	$ 44,139	$ 25,201

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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 thousands)		
Assets:				
Domestic equity*	$ 3,105	$ 1,283	$ —	$ 4,388
International equity*	1,949	1,798	—	3,747
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,274	—	1,274
Mortgage- and asset-backed securities	—	342	—	342
Corporate bonds	—	2,071	—	2,071
Pooled funds	—	937	—	937
Cash equivalents and other	510	1,203	—	1,713
Real estate investments	534	—	2,042	2,576
Private equity	—	—	1,039	1,039
Total	$ 6,098	$ 8,908	$ 3,081	$ 18,087
Liabilities:				
Derivatives	$ (4)	$ —	$ —	$ (4)
Total	$ 6,094	$ 8,908	$ 3,081	$ 18,083

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2013:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 2,778	$ 1,628	$ —	$ 4,406
International equity*	2,136	1,973	—	4,109
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,161	—	1,161
Mortgage- and asset-backed securities	—	303	—	303
Corporate bonds	—	1,897	—	1,897
Pooled funds	—	1,417	—	1,417
Cash equivalents and other	1	433	—	434
Real estate investments	504	—	1,939	2,443
Private equity	—	—	1,108	1,108
Total	$ 5,419	$ 8,812	$ 3,047	$ 17,278
Liabilities:				
Derivatives	$ —	$ (5)	$ —	$ (5)
Total	$ 5,419	$ 8,807	$ 3,047	$ 17,273

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014 Real Estate Investments	**2014** Private Equity	2013 Real Estate Investments	2013 Private Equity
		(in thousands)		
Beginning balance	**$ 1,939**	**$ 1,108**	$ 1,667	$ 1,155
Actual return on investments:				
Related to investments held at year end	**27**	**26**	108	16
Related to investments sold during the year	**60**	**(30)**	57	104
Total return on investments	**87**	**(4)**	165	120
Purchases, sales, and settlements	**16**	**(65)**	107	(167)
Ending balance	**$ 2,042**	**$ 1,039**	$ 1,939	$ 1,108

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014 , 2013 , and 2012 were $4.2 million , $4.1 million , and $4.0 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation 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 Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to a unit co-owned by the Company) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2014 , the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $48.3 million . For 2014 , approximately $4.5 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $43.7 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2)

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continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized ROE midpoint and range by 25 basis points in the event the 30 -year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six - month period.

The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. As a result, the Company recognized an $8.4 million reduction in depreciation expense in 2014.

Pursuant to the Settlement Agreement, the Company may not request an increase in its retail base rates to be effective until after June 2017, unless the Company's actual retail ROE falls below the authorized ROE range.

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company filed such notice with the Florida PSC on July 18, 2014, but no adjustment to the factor was requested for 2014.

At December 31, 2014 and 2013 , the under recovered fuel balance was approximately $39.9 million and $21.0 million , respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2014 and 2013 , the under recovered purchased power capacity balance was approximately $0.3 million and $2.8 million , respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2014 and 2013 , the under recovered environmental balance was approximately $9.8 million and $14.4 million , respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a scrubber on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million , with the Company's portion being $330 million , excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed an appeal by the Sierra Club related to the construction of the scrubber on Plant Daniel Units 1 and 2.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10 -year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

At December 31, 2014 and 2013 , the under recovered energy conservation balance was approximately $2.6 million and $7.0 million , respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

At December 31, 2014 , the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$ 387,511 [a]	$ 285,834
Accumulated depreciation	130,069	177,304
Construction work in progress	2,912	286,343
Company Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $1.8 million .

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in thousands)	
Federal -			
Current	$ 22,771	$ 5,009	$ (92,610)
Deferred	52,602	63,134	161,096
	75,373	68,143	68,486
State -			
Current	(39)	(2,410)	(2,484)
Deferred	12,728	13,935	13,209
	12,689	11,525	10,725
Total	$ 88,062	$ 79,668	$ 79,211

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2014	2013
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$ 776,953	$ 721,087
Property basis differences	52,242	45,960
Fuel recovery clause	16,148	7,972
Pension and other employee benefits	34,405	25,800
Regulatory assets associated with employee benefit obligations	59,788	27,660
Regulatory assets associated with asset retirement obligations	6,768	6,554
Other	21,712	23,947
Total	968,016	858,980
Deferred tax assets-		
Federal effect of state deferred taxes	30,587	24,277
Postretirement benefits	18,033	17,816
Pension and other employee benefits	65,506	33,015
Property reserve	13,440	15,144
Asset retirement obligations	6,768	6,554
Alternative minimum tax carryforward	18,200	18,420
Other	18,893	17,780
Total	171,427	133,006
Net deferred tax liabilities	796,589	725,974
Portion included in current assets/(liabilities), net	3,134	8,381
Accumulated deferred income taxes	$ 799,723	$ 734,355

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2014 , tax-related regulatory assets to be recovered from customers were $56.3 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2014 , the tax-related regulatory liabilities to be credited to customers were $3.9 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.3 million in 2014 and $1.4 million in both 2013 and 2012 . At December 31, 2014 , all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.5**	3.5	3.3
Non-deductible book depreciation	**0.4**	0.5	0.5
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.2)	(0.2)
AFUDC equity	**(1.8)**	(1.1)	(0.9)
Other, net	**0.1**	(0.1)	(0.2)
Effective income tax rate	**37.1%**	37.6%	37.5%

The decrease in the Company's 2014 effective tax rate is primarily the result of an increase in AFUDC equity which is not taxable.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 45**	$ 5,007	$ 2,892
Tax positions increase from current periods	**46**	45	2,630
Tax positions increase/(decrease) from prior periods	**(45)**	(5,007)	515
Reductions due to settlements	**—**	—	(1,030)
Balance at end of year	**$ 46**	$ 45	$ 5,007

The tax positions increase from current periods and decrease from prior periods for 2014 relate primarily to the research and development credit. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 46**	$ 45	$ 45
Tax positions not impacting the effective tax rate	**—**	—	4,962
Balance of unrecognized tax benefits	**$ 46**	$ 45	$ 5,007

The tax positions impacting the effective tax rate for all periods presented relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2010.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had no scheduled maturities of long-term debt due within one year.

Maturities from 2016 through 2019 applicable to total long-term debt are as follows: $110 million in 2016 and $85 million in 2017. There are no scheduled maturities in 2015, 2018, or 2019.

Senior Notes

At each of December 31, 2014 and 2013 , the Company had a total of $1.07 billion and $945 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at December 31, 2014 .

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $309 million and $296 million , respectively.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of

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preferred stock or Class A preferred stock were outstanding at December 31, 2014 . The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50 million . The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million . The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million . There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2014 , committed credit arrangements with banks were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$ 80	$ 165	$ 30	$ 275	$ 275	$ 50	$ —	$ 50	$ 30

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration. Most of the $275 million of unused credit arrangements with banks provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The Company had $69 million of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014. In addition, at December 31, 2014, the Company had $78 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2014 , the Company was in compliance with these covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

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Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014	**$ 110**	**0.3%**
December 31, 2013	$ 136	0.2%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $604.6 million , $532.8 million , and $544.9 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $49.5 million , $21.3 million , and $24.6 million for 2014, 2013, and 2012, respectively.

Estimated total minimum long-term commitments at December 31, 2014 were as follows:

	Operating Lease PPAs
	(in millions)
2015	$ 78.7
2016	78.7
2017	78.8
2018	78.9
2019	78.9
2020 and thereafter	270.3
Total	$ 664.3

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPAs discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $15.0 million , $18.0 million , and $20.1 million for 2014 , 2013 , and 2012 , respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2014 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2015	$ 15.1	$ 0.1	$ 15.2
2016	15.0	0.1	15.1
2017	1.4	0.1	1.5
Total	$ 31.5	$ 0.3	$ 31.8

The Company and Mississippi Power jointly entered into an operating lease agreement for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2.8 million in 2014 , $3.1 million in 2013 , and $3.6 million in 2012 . The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million . The Company has no lease payment obligations for the period 2018 and thereafter.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014 , there were 195 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 432,371 shares, 285,209 shares, and 244,607 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20 , $2.93 , and $3.39 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014 , 2013 , and 2012 was $5.2 million , $1.7 million , and $3.8 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.0 million , $0.6 million , and $1.5 million for the years ended December 31, 2014 , 2013 , and 2012 , respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $11.9 million and $7.7 million , respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three -year performance period which equates to the requisite service period. Employees that retire prior to the end of the three -year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three -year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on

Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 37,829 , 30,627 , and 29,444 , respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54 , $40.50 , and $41.99 , respectively.

The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014 , 2013 , and 2012, total compensation cost for performance share units recognized in income was approximately $1.0 million annually, with the related tax benefit also recognized in income of $0.4 million annually. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014 , there was $1.3 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months .

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2014 , assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 125	$ —	$ 125
Cash equivalents	18,032	—	—	18,032
Total	$ 18,032	$ 125	$ —	$ 18,157
Liabilities:				
Energy-related derivatives	$ —	$ 72,435	$ —	$ 72,435

As of December 31, 2013 , assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 6,962	$ —	$ 6,962
Cash equivalents	15,929	—	—	15,929
Total	$ 15,929	$ 6,962	$ —	$ 22,891
Liabilities:				
Energy-related derivatives	$ —	$ 17,043	$ —	$ 17,043

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013 , the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice Period**
As of December 31, 2014:	*(in thousands)*			
Cash equivalents:				
Money market funds	$18,032	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$15,929	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	**Fair Value**
	(in thousands)	
Long-term debt:		
2014	**$ 1,369,594**	**$ 1,476,954**
2013	$ 1,233,163	$ 1,261,889

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014 , the net volume of energy-related derivative contracts for natural gas positions totaled 84.59 million mmBtu for the Company, with the longest hedge date of 2019 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2014 , there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are not material. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013 , the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 34**	$ 4,893	Liabilities from risk management activities	**$ 36,922**	$ 6,470
	Other deferred charges and assets	**78**	2,069	Other deferred credits and liabilities	**35,502**	10,573
Total derivatives designated as hedging instruments for regulatory purposes		**$ 112**	$ 6,962		**$ 72,424**	$ 17,043

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value				
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in thousands)			*(in thousands)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 125**	$ 6,962	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 72,435**	$ 17,043
Gross amounts not offset in the Balance Sheet [(b)]	**(123)**	(5,775)	Gross amounts not offset in the Balance Sheet [(b)]	**(123)**	(5,775)
Net energy-related derivative assets	**$ 2**	$ 1,187	**Net energy-related derivative liabilities**	**$ 72,312**	$ 11,268

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (36,922)**	$ (6,470)	Other regulatory liabilities, current	**$ 34**	$ 4,893
	Other regulatory assets, deferred	**(35,502)**	(10,573)	Other regulatory liabilities, deferred	**78**	2,069
Total energy-related derivative gains (losses)		**$ (72,424)**	$ (17,043)		**$ 112**	$ 6,962

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For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2014**	2013	2012	**Statements of Income Location**	**2014**	2013	2012
		(in thousands)				*(in thousands)*	
Interest rate derivatives	**$—**	$—	$—	Interest expense, net of amounts capitalized	**$(606)**	$(769)	$(933)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014 , the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014 , the fair value of derivative liabilities with contingent features was $20.5 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2014	**$ 407,132**	**$ 73,888**	**$ 36,743**
June 2014	**383,531**	**68,877**	**34,097**
September 2014	**438,334**	**88,600**	**46,547**
December 2014	**361,485**	**49,850**	**22,789**
March 2013	$ 326,274	$ 51,640	$ 21,792
June 2013	371,173	69,151	32,582
September 2013	399,361	87,776	44,754
December 2013	343,493	56,436	25,301

The Company's business is influenced by seasonal weather conditions.

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	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	**$ 1,590,482**	$ 1,440,301	$ 1,439,762	$ 1,519,812	$ 1,590,209
Net Income After Dividends on Preference Stock (in thousands)	**$ 140,176**	$ 124,429	$ 125,932	$ 105,005	$ 121,511
Cash Dividends on Common Stock (in thousands)	**$ 123,200**	$ 115,400	$ 115,800	$ 110,000	$ 104,300
Return on Average Common Equity (percent)	**11.02**	10.30	10.92	9.55	11.69
Total Assets (in thousands)	**$ 4,708,259**	$ 4,337,571	$ 4,177,402	$ 3,871,881	$ 3,584,939
Gross Property Additions (in thousands)	**$ 360,937**	$ 304,778	$ 325,237	$ 337,830	$ 285,379
Capitalization (in thousands):					
Common stock equity	**$ 1,309,590**	$ 1,235,126	$ 1,180,742	$ 1,124,948	$ 1,075,036
Preference stock	**146,504**	146,504	97,998	97,998	97,998
Long-term debt	**1,369,594**	1,158,163	1,185,870	1,235,447	1,114,398
Total (excluding amounts due within one year)	**$ 2,825,688**	$ 2,539,793	$ 2,464,610	$ 2,458,393	$ 2,287,432
Capitalization Ratios (percent):					
Common stock equity	**46.3**	48.6	47.9	45.8	47.0
Preference stock	**5.2**	5.8	4.0	4.0	4.3
Long-term debt	**48.5**	45.6	48.1	50.2	48.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**388,292**	383,980	379,922	378,248	376,561
Commercial	**54,892**	54,567	53,808	53,450	53,263
Industrial	**260**	260	264	273	272
Other	**603**	582	577	565	562
Total	**444,047**	439,389	434,571	432,536	430,658
Employees (year-end)	**1,384**	1,410	1,416	1,424	1,330

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	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	**$ 700,442**	$ 632,495	$ 609,454	$ 637,352	$ 707,196
Commercial	**408,401**	395,062	389,936	408,389	439,468
Industrial	**153,167**	138,585	140,490	158,367	157,591
Other	**4,530**	3,858	4,591	4,382	4,471
Total retail	**1,266,540**	1,170,000	1,144,471	1,208,490	1,308,726
Wholesale — non-affiliates	**129,151**	109,386	106,881	133,555	109,172
Wholesale — affiliates	**130,107**	99,577	123,636	111,346	110,051
Total revenues from sales of electricity	**1,525,798**	1,378,963	1,374,988	1,453,391	1,527,949
Other revenues	**64,684**	61,338	64,774	66,421	62,260
Total	**$ 1,590,482**	$ 1,440,301	$ 1,439,762	$ 1,519,812	$ 1,590,209
Kilowatt-Hour Sales (in thousands):					
Residential	**5,362,423**	5,088,828	5,053,724	5,304,769	5,651,274
Commercial	**3,838,148**	3,809,939	3,858,521	3,911,399	3,996,502
Industrial	**1,849,255**	1,700,174	1,725,121	1,798,688	1,685,817
Other	**25,236**	20,946	25,267	25,430	25,602
Total retail	**11,075,062**	10,619,887	10,662,633	11,040,286	11,359,195
Wholesale — non-affiliates	**1,670,121**	1,162,308	977,395	2,012,986	1,675,079
Wholesale — affiliates	**3,283,685**	3,127,350	4,369,964	2,607,873	2,436,883
Total	**16,028,868**	14,909,545	16,009,992	15,661,145	15,471,157
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**13.06**	12.43	12.06	12.01	12.51
Commercial	**10.64**	10.37	10.11	10.44	11.00
Industrial	**8.28**	8.15	8.14	8.80	9.35
Total retail	**11.44**	11.02	10.73	10.95	11.52
Wholesale	**5.23**	4.87	4.31	5.30	5.33
Total sales	**9.52**	9.25	8.59	9.28	9.88
Residential Average Annual					
Kilowatt-Hour Use Per Customer	**13,865**	13,301	13,303	14,028	15,036
Residential Average Annual					
Revenue Per Customer	**$ 1,811**	$ 1,653	$ 1,604	$ 1,685	$ 1,882
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	**2,663**	2,663	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,684**	1,729	2,130	2,485	2,544
Summer	**2,424**	2,356	2,344	2,527	2,519
Annual Load Factor (percent)	**51.1**	55.9	56.3	54.5	56.1
Plant Availability Fossil-Steam (percent)*	**89.4**	92.8	82.5	84.7	94.7
Source of Energy Supply (percent):					
Coal	**44.5**	36.4	34.6	49.4	64.6
Gas	**22.2**	23.0	23.5	24.0	17.8
Purchased power —					
From non-affiliates	**28.9**	37.0	40.2	22.3	13.2
From affiliates	**4.4**	3.6	1.7	4.3	4.4
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2014 Annual Report

The management of Mississippi Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014 .

/s/ G. Edison Holland, Jr.
G. Edison Holland, Jr.
Chairman, President, and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

**To the Board of Directors of
Mississippi Power Company**

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-387 to II-435) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2014 and 2013 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014 , in conformity with accounting principles generally accepted in the United States of America.

/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
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
APA	Asset purchase agreement
ASC	Accounting Standards Codification
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECM	Energy cost management clause
ECO	Environmental compliance overview
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mirror CWIP	A regulatory liability account for use in mitigating future rate impacts for customers
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
OCI	Other comprehensive income
PEP	Performance evaluation plan
Plant Daniel Units 3 and 4	Combined cycle Units 3 and 4 at Plant Daniel
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system

DEFINITIONS
(continued)

Term	Meaning
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SRR	System Restoration Rider
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2014 Annual Report

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain and grow energy sales and to maintain a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of major construction projects, primarily the Kemper IGCC and the Plant Daniel scrubber project, projected long-term demand growth, reliability, fuel, and increasingly stringent environmental standards, as well as ongoing capital expenditures required for maintenance. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC established by the Mississippi PSC was $2.4 billion with a construction cost cap of $2.88 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions).

The Company's current cost estimate for the Kemper IGCC in total is approximately $6.20 billion, which includes approximately $4.93 billion of costs subject to the construction cost cap. The Company does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company has recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively.

The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC project in service on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The in-service date for the remainder of the Kemper IGCC is currently expected to occur in the first half of 2016. The current cost estimate includes costs through March 31, 2016. As a result of the additional factors that have the potential to impact start-up and operational readiness activities for this first-of-a-kind technology as described herein, the risk of further schedule extensions and/or cost increases, which could be material, remains. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information, including the discussion of risks related to the Kemper IGCC.

On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in a legal challenge filed by Thomas A. Blanton with respect to the Mississippi PSC's March 2013 order that authorized the collection of $156 million annually (2013 MPSC Rate Order) to be recorded as Mirror CWIP. The Court reversed the 2013 MPSC Rate Order, deemed the 2013 Settlement Agreement (defined below) between the Company and the Mississippi PSC unenforceable due to a lack of public notice for the related proceedings, and directed the Mississippi PSC to enter an order requiring the Company to refund the Mirror CWIP amounts collected pursuant to the 2013 MPSC Rate Order. As of December 31, 2014, $257.2 million had been collected by the Company. The Company continues to analyze the Court's opinion and expects to file a motion for rehearing. See "2015 Mississippi Supreme Court Decision" herein for additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including the construction and start-up of the Kemper IGCC, to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile in measuring performance, which the Company achieved during 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2014 fossil Peak Season EFOR of 0.55% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's 2014 performance was better than the target for these transmission and distribution reliability measures.

The Company uses net income (loss) after dividends on preferred stock as the primary measure of the Company's financial performance. The Company's results were below target for 2014 due to the increased cost estimate for the Kemper IGCC above the $2.88 billion cost cap and the 2015 Court decision. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Performance Evaluation Plan" and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's net income (loss) after dividends on preferred stock was ($328.7) million in 2014 compared to ($476.6) million in 2013. The decreased net loss in 2014 was primarily the result of lower pre-tax charges of $868.0 million ($536.0 million after tax) in 2014 compared to pre-tax charges of $1.1 billion ($680.5 million after-tax) in 2013 for revisions of estimated costs expected to be incurred on the Company's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. The change was also due to wholesale base rate increases, effective in April 2013 and May 2014, and an increase in AFUDC equity primarily related to the construction of the Kemper IGCC. These changes were partially offset by a decrease in retail revenues primarily as a result of the 2015 Court decision which required the reversal of revenues recorded in 2013, increases in non-fuel operations and maintenance expenses and interest expense. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net income (loss) after dividends on preferred stock was ($476.6) million in 2013 compared to $99.9 million in 2012. The decrease in 2013 was primarily the result of pre-tax charges of $1.1 billion ($680.5 million after-tax) for revisions of estimated costs expected to be incurred on the Company’s construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. These charges were partially offset by an increase in AFUDC equity primarily related to the construction of the Kemper IGCC which began in 2010 and an increase in revenues primarily due to retail and wholesale base rate increases and a retail rate increase related to the Kemper IGCC cost recovery that became effective in April 2013. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

RESULTS OF OPERATIONS

A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	**2014**	2013
		(in millions)	
Operating revenues	**$ 1,242.6**	**$ 97.5**	$ 109.2
Fuel	**574.0**	**82.7**	80.0
Purchased power	**42.9**	**(5.4)**	(6.8)
Other operations and maintenance	**270.7**	**17.3**	24.7
Depreciation and amortization	**97.1**	**5.7**	4.9
Taxes other than income taxes	**79.1**	**(1.5)**	1.2
Estimated loss on Kemper IGCC	**868.0**	**(234.0)**	1,024.0
Total operating expenses	**1,931.8**	**(135.2)**	1,128.0
Operating income	**(689.2)**	**232.7**	(1,018.8)
Allowance for equity funds used during construction	**136.4**	**14.8**	56.8
Interest expense, net of amounts capitalized	**(45.3)**	**(8.8)**	(4.4)
Other income (expense), net	**(14.1)**	**(8.1)**	(7.3)
Income taxes (benefit)	**(285.2)**	**82.6**	(388.4)
Net income (loss)	**(327.0)**	**148.0**	(576.5)
Dividends on preferred stock	**1.7**	**—**	—
Net income (loss) after dividends on preferred stock	**$ (328.7)**	**$ 148.0**	$ (576.5)

Operating Revenues

Operating revenues for 2014 were $1.2 billion, reflecting a $97.5 million increase from 2013 . Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	**$ 799.1**	$ 747.5
Estimated change resulting from —		
Rates and pricing	**(11.5)**	18.2
Sales growth (decline)	**(1.5)**	(0.7)
Weather	**2.9**	1.2
Fuel and other cost recovery	**5.6**	32.9
Retail — current year	**794.6**	799.1
Wholesale revenues —		
Non-affiliates	**322.7**	293.9
Affiliates	**107.2**	34.8
Total wholesale revenues	**429.9**	328.7
Other operating revenues	**18.1**	17.4
Total operating revenues	**$ 1,242.6**	$ 1,145.2
Percent change	**8.5%**	10.5%

Total retail revenues for 2014 decreased $4.5 million, or 0.6%, compared to 2013 primarily as a result of $10.3 million in revenues recorded in 2013 that were reversed in 2014 as a result of the 2015 Court decision. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" for additional information. This decrease was partially offset by a PEP base rate increase, effective in March 2013, of $2.8 million and a $4.7 million refund in 2013 related to the annual PEP lookback filing. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information. Total retail revenues for 2013 increased $51.6 million, or 6.9%, compared to 2012 primarily as a result of a base rate increase, a rate increase related to Kemper IGCC cost recovery that became effective in April 2013, and higher fuel cost recovery revenues in 2013 compared to 2012.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information. Fuel and other cost recovery revenues increased in 2014 and 2013 compared to prior years primarily as a result of higher recoverable fuel costs.

Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2014	2013	2012
		(in millions)	
Capacity and other	**$ 160.3**	$ 143.0	$ 122.5
Energy	**162.4**	150.9	133.1
Total non-affiliated	**$ 322.7**	$ 293.9	$ 255.6

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 21.9% of the Company’s total operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

Wholesale revenues from sales to non-affiliates increased $28.8 million, or 9.8%, in 2014 compared to 2013 as a result of a $17.3 million increase in base revenues primarily resulting from wholesale base rate increases effective April 1, 2013 and May 1, 2014 and an $11.5 million increase in energy revenues, of which $10.0 million was associated with an increase in KWH sales and $1.5 million was associated with higher fuel prices. Wholesale revenues from sales to non-affiliates increased $38.4 million, or 15.0%, in 2013 compared to 2012 as a result of a $20.5 million increase in base revenues primarily resulting from a wholesale base rate increase effective April 1, 2013 and a $17.8 million increase in energy revenues, of which $14.0 million was associated with higher fuel prices and $3.8 million was associated with an increase in KWH sales.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliates will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Wholesale revenues from sales to affiliates increased $72.4 million, or 208.3%, in 2014 compared to 2013 primarily due to a $74.6 million increase in energy revenues of which $69.3 million was associated with an increase in KWH sales and $5.3 million was associated with higher prices, partially offset by a decrease in capacity revenues of $2.2 million. Wholesale revenues from sales to affiliates increased $18.4 million, or 112.0%, in 2013 compared to 2012 due to a $1.3 million increase in capacity revenues and a $17.1 million increase in energy revenues of which $7.2 million was associated with higher prices and $9.9 million was associated with an increase in KWH sales.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Other operating revenues in 2014 increased $0.7 million, or 4.2%, from 2013 primarily due to a $1.3 million increase in transmission revenues, partially offset by a $0.6 million decrease in microwave tower lease revenue and a $0.2 million decrease in miscellaneous revenues from timber and easement sale proceeds. Other operating revenues in 2013 increased $0.8 million, or 4.8%, from 2012 primarily due to a $0.5 million increase in transmission revenues and a $0.3 million increase in miscellaneous revenue from timber and easement sale proceeds.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	**2014**	2013	**2014**	2013
	(in millions)				
Residential	**2,126**	**1.8 %**	2.0 %	**(2.3)%**	— %
Commercial	**2,859**	**(0.2)**	(1.7)	**0.1**	(1.1)
Industrial	**4,943**	**4.3**	0.8	**4.3**	0.8
Other	**41**	**1.1**	4.0	**1.1**	4.0
Total retail	**9,969**	**2.4**	0.3 %	**1.6 %**	0.1 %
Wholesale					
Non-affiliated	**4,191**	**6.7**	2.9		
Affiliated	**2,900**	**211.4**	62.8		
Total wholesale	**7,091**	**45.9**	10.7		
Total energy sales	**17,060**	**16.9 %**	3.5 %		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential energy sales increased 1.8% in 2014 compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Weather-adjusted residential energy sales decreased 2.3% in 2014 compared to 2013 due to lower average usage per customer. Household income, one of the primary drivers of residential customer usage, was flat in 2014. Residential energy sales increased 2.0% in 2013 compared to 2012 due to less mild weather and a slight increase in the number of residential customers in 2013 compared to 2012.

Commercial energy sales decreased 1.7% in 2013 compared to 2012 due to decreased economic activity in 2013 compared to 2012.

Industrial energy sales increased 4.3% in 2014 compared to 2013 due to increased production related to expanded operation by many industrial customers. Industrial energy sales increased 0.8% in 2013 compared to 2012 due to increased usage by larger industrial customers as well as expansions by existing customers.

Wholesale energy sales to non-affiliates increased 6.7% in 2014 compared to 2013 primarily due to increased opportunity sales to the external market as a result of lower system prices. Wholesale energy sales to non-affiliates increased 2.9% in 2013 compared to 2012 primarily due to increased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from less mild weather in 2013 compared to 2012.

Wholesale sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Wholesale energy sales to affiliates increased 211.4% in 2014 compared to 2013 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies. Wholesale energy sales to affiliates increased 62.8% in 2013 compared to 2012 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2014	2013	2012
Total generation *(millions of KWHs)*	**16,881**	13,721	12,750
Total purchased power *(millions of KWHs)*	**886**	1,559	1,961
Sources of generation *(percent)* –			
Coal	**42**	36	26
Gas	**58**	64	74
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.96**	4.97	5.09
Gas	**3.37**	3.16	2.90
Average cost of fuel, generated *(cents per net KWH)*	**3.64**	3.87	3.53
Average cost of purchased power *(cents per net KWH)*	**4.85**	3.10	2.81

Fuel and purchased power expenses were $616.9 million in 2014, an increase of $77.3 million, or 14.3%, above the prior year costs. The increase was primarily due to a $114.4 million increase in the total volume of KWHs generated, offset by a $37.1 million decrease in the cost of fuel and purchased power. Fuel and purchased power expenses were $539.6 million in 2013, an increase of $73.2 million, or 15.7%, above the prior year costs. The increase was primarily due to a $55.1 million increase in the total volume of KWHs generated and purchased and an $18.1 million increase in the cost of fuel and purchased power.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense increased $82.7 million, or 16.8%, in 2014 compared to 2013. The increase was the result of a 24.5% increase in the volume of KWHs generated in 2014, partially offset by a 5.9% decrease in the average cost of fuel per KWH generated. Fuel expense increased $80.0 million, or 19.5%, in 2013 compared to 2012. The increase was the result of a 9.6% increase in the average cost of fuel per KWH generated and a 9.0% increase in the volume of KWHs generated resulting from increased non-territorial sales in 2013 compared to 2012.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates increased $12.1 million, or 210.3%, in 2014 compared to 2013. The increase was primarily the result of a 276.7% increase in the average cost per KWH purchased, partially offset by a 17.6% decrease in the volume of KWHs purchased. Purchased power expense from non-affiliates increased $0.5 million, or 10.2%, in 2013 compared to 2012. The increase was the result of an 8.0% increase in the average cost per KWH purchased and a 2.0% increase in the volume of KWHs purchased. The increase in the average cost per KWH purchased was due to a higher marginal cost of fuel. The increase in the volume of KWHs purchased was due to a lower market cost of available energy compared to the cost of generation.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power - Affiliates

Purchased power expense from affiliates decreased $17.5 million, or 41.1%, in 2014 compared to 2013. The decrease in 2014 was primarily the result of a 49.5% decrease in the volume of KWHs purchased, offset by a 16.8% increase in the average cost per KWH purchased compared to 2013. Purchased power expense from affiliates decreased $7.3 million, or 14.7%, in 2013 compared to 2012. The decrease was primarily the result of a 24.7% decrease in the volume of KWHs purchased, partially offset by a 13.2% increase in the average cost per KWH purchased compared to 2012.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $17.3 million, or 6.8%, in 2014 compared to 2013 primarily due to a $14.1 million increase in employee compensation and benefit expenses and a $6.5 million increase in generation maintenance expenses. These increases in 2014 were partially offset by a $2.0 million decrease in transmission expenses primarily related to overhead line maintenance and vegetation management, and a $0.8 million decrease in customer accounting expenses primarily due to uncollectibles.

Other operations and maintenance expenses increased $24.7 million, or 10.8%, in 2013 compared to 2012 primarily due to a $9.8 million increase in generation maintenance expenses for several planned outages, a $7.6 million increase in administrative and general expenses related to pension expense, a $4.2 million increase in transmission maintenance expenses, a $2.8 million increase in customer accounting primarily due to uncollectibles, and a $2.5 million increase in distribution expenses related to overhead line maintenance and vegetation management. These increases were partially offset by a $2.7 million decrease in labor expenses.

Depreciation and Amortization

Depreciation and amortization increased $5.7 million, or 6.3%, in 2014 compared to 2013 primarily due to a $4.2 million increase related to the reversal of a regulatory deferral associated with the Kemper IGCC municipal franchise taxes, a $2.2 million increase in depreciation related to an increase in assets in service, and a $2.2 million increase resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4. These increases were partially offset by a $3.7 million decrease associated with a wholesale revenue requirement adjustment.

Depreciation and amortization increased $4.9 million, or 5.7%, in 2013 compared to 2012 primarily due to a $4.3 million increase in ECO Plan amortization, a $2.0 million increase in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, and a $1.6 million increase in depreciation resulting from an increase in plant in service. These increases were partially offset by a $2.1 million decrease in amortization primarily resulting from a regulatory deferral associated with the Kemper IGCC and a $0.7 million decrease in amortization resulting from a regulatory deferral associated with the capital lease related to the Kemper IGCC air separation unit.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters," "Retail Regulatory Matters – Performance Evaluation Plan," and " – Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $1.5 million, or 2.0%, in 2014 compared to 2013 primarily as a result of a $6.0 million decrease in franchise taxes, partially offset by a $3.2 million increase in ad valorem taxes and a $1.3 million increase in payroll taxes. Taxes other than income taxes increased $1.2 million, or 1.6%, in 2013 compared to 2012 primarily as a result of a $3.5 million increase in franchise taxes, partially offset by a $2.1 million decrease in ad valorem taxes and a $0.2 million decrease in payroll taxes.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

Estimated probable losses on the Kemper IGCC of $868.0 million and $1.1 billion were recorded in 2014 and 2013, respectively, to reflect revisions of estimated costs expected to be incurred on the construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $14.8 million, or 12.2%, in 2014 as compared to 2013 and $56.8 million, or 87.7%, in 2013 as compared to 2012. These increases in 2014 and 2013 were primarily due to CWIP related to the Company's Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During

Construction" and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $8.8 million, or 24.2%, in 2014 compared to 2013, primarily due to an $11.0 million increase in interest expense resulting from the receipt of $75.0 million and $50.0 million interest-bearing refundable deposits from SMEPA in January 2014 and October 2014, respectively, related to its pending purchase of an undivided interest in the Kemper IGCC, an $8.2 million increase in interest expense on the regulatory liability related to the Kemper IGCC rate recovery, a $4.6 million increase in interest expense primarily associated with the issuances of long-term debt in 2014, and a $2.8 million increase in other interest expense. These increases in 2014 over the prior year were partially offset by a $14.6 million increase in capitalized interest resulting from carrying costs associated with the Kemper IGCC and a $3.2 million decrease in interest expense primarily associated with the redemption of long-term debt in late 2013.

Interest expense, net of amounts capitalized decreased $4.4 million, or 10.7%, in 2013 compared to 2012, primarily due to a $20.1 million increase in capitalized interest resulting from AFUDC debt associated with the Kemper IGCC and a $2.6 million decrease in interest expense associated with the redemption of long-term debt in 2013. These decreases in 2013 from the prior year were partially offset by a $12.2 million increase in interest expense primarily associated with the issuances of new long-term debt in 2013, a $4.0 million increase in interest expense resulting from the receipt of a $150.0 million interest-bearing refundable deposit from SMEPA in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC, and a $2.7 million increase in interest expense in the regulatory liability related to the Kemper IGCC rate recovery.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Proposed Sale of Undivided Interest to SMEPA" for more information.

Other Income (Expense), Net

Other income (expense), net decreased $8.1 million, or 133.7%, in 2014 compared to 2013 primarily due to $7.0 million associated with the Sierra Club settlement and a $1.1 million increase in consulting fees. Other income (expense), net decreased $7.3 million in 2013 compared to 2012 primarily due to a $5.9 million increase in consulting fees. See "Other Matters – Sierra Club Settlement Agreement" herein and Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

Income Taxes (Benefit)

Income taxes (benefit) increased $82.6 million, or 22.5%, in 2014 compared to 2013 and decreased $388.4 million in 2013 compared to 2012 primarily resulting from the reduction in pre-tax losses related to the estimated probable losses on the Kemper IGCC.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein, and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to prevail against legal challenges associated with the Kemper IGCC, recover its prudently-incurred costs in a timely manner during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and the Plant Daniel scrubber project as well as other ongoing construction projects.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the Company had invested approximately $523 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $118 million, $104 million, and $52 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $154 million from 2015 through 2017, with annual totals of approximately $94 million, $25 million, and $35 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, CCR, global climate change, or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the Company's commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $393 million in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

Final revisions to the NAAQS for sulfur dioxide (SO_2) , which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units, including units co-owned by the Company. In March 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and the Company and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power and the Company believe this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units co-owned by the Company.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama and Mississippi) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of the eight-hour ozone and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the

Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" and "Other Matters – Sierra Club Settlement Agreement" for additional information.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

These proposed and final water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Coal Combustion Residuals

The Company currently manages two electric generating plants in Mississippi and is also part owner of a plant located in Alabama, each with onsite CCR storage units consisting of landfills and surface impoundments (CCR Units) . In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Mississippi and Alabama each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $64 million and ongoing post-closure care of approximately $12 million. The Company will record asset retirement obligations (ARO) for the estimated closure costs required under the CCR Rule during 2015. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 10 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 11 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

In May 2013, the FERC accepted a settlement agreement entered into by the Company with its wholesale customers which approved, among other things, the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC for certain items. The regulatory treatment includes (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules. See Note 3 to the financial statements under "FERC Matters" for more information.

On March 31, 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC on May 20, 2014, provides that base rates under the MRA cost-based electric tariff will increase approximately $10.1 million annually, with revised rates effective for services rendered beginning May 1, 2014.

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as the Kemper IGCC, fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In March 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Energy Efficiency

In July 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards.

On June 3, 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. On October 20, 2014, the Company filed a revised compliance filing, which proposed an increase of $6.7 million in retail revenues for the period December 2014 through December 2015. The Mississippi PSC approved the revised filing on November 4, 2014.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n May 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million . Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

In March 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9% , or $15.3 million , annually, effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 18, 2014, the Company submitted its annual PEP lookback filing for 2013, which indicated no surcharge or refund. On March 31, 2014, the Mississippi PSC suspended the filing to allow more time for review.

On June 3, 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

The ultimate outcome of these matters cannot be determined at this time.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. On August 1, 2014, the Company entered into a settlement agreement with the Sierra Club (Sierra Club Settlement Agreement) that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed the Sierra Club's appeal related to the CPCN to construct scrubbers on Plant Daniel Units 1 and 2.

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2014, $5.6 million of Plant Greene County costs and $2.0 million of costs related to Plant Watson have been reclassified as a regulatory asset. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2015 and 2016, respectively. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

See Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

On February 25, 2015, the Company submitted its annual ECO filing for 2015, which indicated an annual increase in revenues of approximately $8.1 million.

The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; the most recent filing occurred on November 17, 2014. On January 13, 2015, the Mississippi PSC approved the 2015 retail fuel cost recovery factor, effective January 21, 2015. The retail fuel cost recovery factor will result in an annual increase of approximately $7.9 million . At December 31, 2014, the amount of under-recovered retail fuel costs included in the balance sheets was $2.5 million compared to a $14.5 million over-recovered balance at December 31, 2013.

The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2015, the wholesale MRA fuel rate decreased resulting in an annual decrease of $1.1 million. Effective February 1, 2015, the wholesale MB fuel rate decreased, resulting in an annual decrease of $0.1 million. At December 31, 2014, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $0.2 million compared to an over-recovered balance of $7.3 million at December 31, 2013. At December 31, 2014, the amount of over-recovered wholesale MB fuel costs included in the balance sheets was immaterial compared to an over-recovered balance of $0.3 million at December 31, 2013. In addition, at December 31, 2014, the amount of over-recovered MRA emissions allowance cost included in the balance sheets was $0.3 million compared to a $3.8 million under-recovered balance at December 31, 2013. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On May 6, 2014, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2014, in which the Company requested an annual rate increase of 0.38%, or $3.6 million in annual retail revenues, primarily due to an increase in property tax rates.

See RESULTS OF OPERATIONS – "Taxes Other Than Income Taxes" herein for additional information.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. In the Court decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and " – 2015 Mississippi Supreme Court Decision" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC .

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245.3 million of DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC.

The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Recovery of the Kemper IGCC costs subject to the cost cap and the Cost Cap Exceptions remain subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate [f]	Current Estimate	**Actual Costs at 12/31/2014**
		(in billions)	
Plant Subject to Cost Cap [a]	$ 2.40	$ 4.93	**$ 4.23**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.10**
AFUDC [b][c]	0.17	0.63	**0.45**
Combined Cycle and Related Assets Placed in Service – Incremental [d]	—	0.02	0.00
General Exceptions	0.05	0.10	**0.07**
Deferred Costs [c][e]	—	0.18	**0.12**
Total Kemper IGCC [a][c]	$ 2.97	$ 6.20	**$ 5.20**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014, $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 to the financial statements under "Retail Regulatory Matters – Baseload Act" for additional information. See "Income Tax Matters" herein for additional tax information related to the Kemper IGCC.

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements.

2013 Settlement Agreement

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that, among other things, established the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The 2013 Settlement Agreement also allowed the Company to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in February 2013. The Company's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact the Company's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC Rate Order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service .

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC through the in-service date. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. The Company will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, the Company provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. The Company's analysis requested, among other things, confirmation of the Company's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, the Company's August 18, 2014 filing with the Mississippi PSC requested confirmation of the Company's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under the Company's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by the Company could have a material impact on the results of operations, financial condition, and liquidity of the Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, the Company had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. The Company is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying the Company's request for rehearing. The Company is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, the Company proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning in March 2013, was integral to the Rate Mitigation Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Rate Mitigation Plan, the Company proposed annual rate recovery to remain the same from 2014 through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of 2020, the Mississippi PSC would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" and "Income Tax Matters" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or the Company withdraws the Rate Mitigation Plan, the Company would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion , the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and the Company is working to reach a mutually acceptable resolution. As a result of the Court's decision, the Company intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

On August 18, 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million . The projected balance at March 31, 2016 is estimated to total approximately $269.8 million . The amortization period of 40 years proposed by the Company for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. The Company is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. The Company is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million .

See "2015 Mississippi Supreme Court Decision" for additional information.

See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that the Company does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While the Company has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues and could have a material financial impact on the Company to the extent the Company is not able to enter into other similar contractual arrangements.

The ultimate outcome of these matters cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, the Company and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, the Company and SMEPA signed an amendment to the APA whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the 2011 power supply agreement were $16.7 million in 2014. In December 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, the Company and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) the Company agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified the Company that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, the Company received $150 million , $75 million , and $50 million , respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, the Company would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposit s.

The ultimate outcome of these matters cannot be determined at this time.

Income Tax Matters

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information about the Kemper IGCC. The ultimate outcome of these tax matters cannot be determined at this time.

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

Investment Tax Credits

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A tax credits to the Company in connection with the Kemper IGCC. Through December 31, 2014, the Company had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. The Company currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, the Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014 . See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

In February 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

Sierra Club Settlement Agreement

On August 1, 2014, the Company entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the scrubber project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.

Under the Sierra Club Settlement Agreement, the Company agreed to, among other things, fund a $15 million grant payable over a 15 -year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, the Company paid $7 million in 2014, recognized in other income (expense), net in the statement of operations. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial position, results of operations, or cash flows.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $30.2 million and $5.2 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $4.1 million and $0.6 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.8 million or less change in total annual benefit expense and a $22.7 million or less change in projected obligations.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.91% , 6.89% , and 7.04% for the years ended December 31, 2014 , 2013 , and 2012 , respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $136.4 million, $121.6 million, and $64.8 million in 2014, 2013, and 2012, respectively.

Kemper IGCC Estimated Construction Costs, Project Completion Date, and Rate Recovery

During 2014, the Company further extended the scheduled in-service date for the Kemper IGCC to the first half of 2016 and revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek any rate recovery or any joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, $462.0 million ($285.3 million after tax) in the first quarter 2013, and $78.0 million ($48.2 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014 .

The Company has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the statements of operations and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

The Company's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Given the significant judgment involved in estimating the future costs to complete construction and start-up, the project completion date, the ultimate rate recovery for the Kemper IGCC, and the potential impact on the results of operations, the Company considers these items to be critical accounting estimates. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2014 and 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC and by the Court's decision to reverse the 2013 MPSC Rate order; however, the Company's financial condition remained stable at December 31, 2014 and December 31, 2013 as a result of capital contributions to the Company by Southern Company. The Company's cash requirements primarily consist of funding debt maturities, including $775 million of bank loans maturing in 2015, ongoing operations, capital expenditures, and the potential requirement to refund amounts collected under the 2013 MPSC Rate Order ($257.2 million through December 31, 2014) and additional amounts for associated carrying costs. See FUTURE EARNINGS POTENTIAL – Integrated Coal Gasification Combined Cycle – "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" herein for additional information. For the three-year period from 2015 through 2017, the Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, including the Plant Daniel scrubber project, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Through December 31, 2014, the Company has incurred non-recoverable cash expenditures of $1.3 billion and is expected to incur approximately $702 million in additional non-recoverable cash expenditures through completion of the Kemper IGCC.

In 2014, the Company received $450.0 million in equity contributions and a $220.0 million loan from Southern Company which was repaid on September 29, 2014. In January 2015, the Company received an additional $75.0 million in equity contributions from Southern Company. The Company is currently negotiating to refinance its maturing bank loans and to obtain additional bank loans. The Company also intends to utilize cash from operations and commercial paper and lines of credit as market conditions permit, as well as, under certain circumstances, equity contributions and/or loans from Southern Company, to fund the Company's short-term capital needs.

See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $33 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015.

Net cash provided from operating activities totaled $734.4 million for 2014, an increase of $286.8 million as compared to the corresponding period in 2013. The increase in net cash provided from operating activities was primarily due to deferred income taxes and Mirror CWIP, net of the Kemper IGCC regulatory deferral, partially offset by a decrease in ITCs received related to the Kemper IGCC, an increase in prepaid income taxes, increases in fossil fuel stock, and an increase in regulatory assets associated with the Kemper IGCC. Net cash provided from operating activities totaled $447.6 million for 2013, an increase of $212.2 million as compared to the corresponding period in 2012. The increase in net cash provided from operating activities was primarily due to an increase in ITCs received related to the Kemper IGCC, increases in rate recovery related to the Kemper IGCC, and decreases in fossil fuel stock, partially offset by a decrease in over-recovered regulatory clause revenues and an increase in regulatory assets associated with the Kemper IGCC.

Net cash used for investing activities totaled $1.3 billion for 2014 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber project. Net cash used for investing activities totaled $1.6 billion for 2013 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber project, partially offset by proceeds from asset sales.

Net cash provided from financing activities totaled $592.6 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits related to a pending asset sale, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $1.2 billion in 2013 primarily due to an increase in capital contributions from Southern Company and an increase in long-term debt financings, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2014 compared to 2013 included an increase in securities due within one year of $763.9 million and a decrease in long-term debt of $536.6 million, primarily due to bank loans maturing in 2015, as well as an increase in the interest-bearing refundable deposit from SMEPA of $125.0 million. See "Financing Activities" herein for additional information. Total property, plant, and equipment increased $416.6 million and other regulatory assets, deferred increased $184.8 million primarily due to the Kemper IGCC and results of an actuarial study. See "Integrated Coal Gasification Combined Cycle" herein for additional information. Other regulatory liabilities, deferred decreased $81.3 million and Mirror CWIP increased $270.8 million primarily due to the reclassification of Kemper regulatory liabilities. Additional changes included an increase in accrued income taxes of $136.9 million primarily due to R&E tax deductions, an increase in prepaid income taxes of $155.9 million primarily due to ITCs related to the Kemper IGCC and an increase in taxes on Mirror CWIP, a net increase in accumulated deferred income taxes of $194.7 million primarily related to the Kemper combined cycle and associated common facilities placed in service on August 9, 2014 offset by the estimated probable loss on the Kemper IGCC, an increase in employee benefit obligations of $53.1 million, and an increase in deferred charges related to income taxes of $81.8 million. See Note 2 and Note 5 to the financial statements for additional information. Total common stockholder's equity decreased $92.3 million primarily due to the estimated probable loss on the Kemper IGCC partially offset by the receipt of $450.0 million in capital contributions from Southern Company.

The Company's ratio of common equity to total capitalization, including long-term debt due within one year, was 46.1% in 2014 and 49.6% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described herein, the Company plans to obtain the funds required for construction and other purposes from operating cash flows, security issuances, term loans, and/or short-term debt, as well as, under certain circumstances, equity contributions and/or loans from Southern Company. Operating cash flows would be adversely impacted by $156 million annually with the removal of rates implemented under the 2013 MPSC Rate Order. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which may include resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein for additional information. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" included herein for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The Company received $245.3 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for commercial operation of the Kemper IGCC. In addition, see FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require approval by the Mississippi PSC.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2014, the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $775 million of bank loans maturing in 2015, an interest-bearing refundable deposit from SMEPA, and the potential Mirror CWIP refund. The Company is currently negotiating to refinance its maturing bank loans and to obtain additional bank loans. The Company also intends to utilize cash from operations, and commercial paper and lines of credit as market conditions permit, as well as, under certain circumstances, equity contributions and/or loans from Southern Company, to fund the Company's short-term capital needs. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

At December 31, 2014, the Company had approximately $132.5 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires				Executable Term-Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)				
$ 135	$ 165	$ 300	$ 300	$ 25	$ 40	$ 65	$ 70

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company expects to renew its credit arrangements, as needed prior to expiration.

Most of these bank credit arrangements contain covenants that limit debt levels and typically contain cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

A portion of the $300 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $40.1 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

The Company had no short-term borrowings in 2012 and 2014. Details of short-term borrowing for 2013 were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2013	$—	—%	$23	0.2%	$148

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31.

Financing Activities

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm restoration costs, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Bank Term Loans

In January 2014, the Company entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

This and other bank loans and the other revenue bonds described below have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014 , the Company was in compliance with its debt limits.

In addition, this and other bank loans and the other revenue bonds described below contain cross default provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold. The Company is currently in compliance with all such covenants.

Other Revenue Bonds

In May 2014 and August 2014, the Mississippi Business Finance Corporation (MBFC) issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of the Company and proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity.

Other Obligations

In 2012, January 2014, and October 2014, the Company received $150 million, $75 million, and $50 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

In May 2014, the Company issued a 19-month floating rate promissory note to Southern Company for a loan bearing interest based on one-month LIBOR. This loan was for $220 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's construction program. This loan was repaid on September 29, 2014.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel transportation and storage, and energy price risk management. At December 31, 2014 , the maximum amount of potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 equaled approximately $280 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Subsequent to December 31, 2014, Moody's affirmed the senior unsecured debt rating of the Company and revised the ratings outlook for the Company from stable to negative.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $815 million of long-term variable interest rate exposure at December 31, 2014 was 0.96%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $8 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2014 Changes	2013 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (5,478)**	$ (16,927)
Contracts realized or settled	**(2,655)**	11,271
Current period changes [(a)]	**(37,231)**	178
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (45,364)**	$ (5,478)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The net hedge volumes of energy-related derivative contracts, all of which are natural gas swaps, for the years ended December 31 were as follows:

	2014	2013
	mmBtu Volume	
	(in thousands)	
Total hedge volume	**54,220**	56,440

The weighted average swap contract cost above market prices was approximately $0.84 per mmBtu as of December 31, 2014 and $0.10 per mmBtu as of December 31, 2013. There were no options outstanding as of the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of operations as incurred and were not material for any year presented. The pre-tax gains and losses reclassified from OCI to revenue and fuel expense were not material for any period presented and are not expected to be material for 2015.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in thousands)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(45,364)	(26,227)	(18,620)	(517)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (45,364)	$ (26,227)	$ (18,620)	$ (517)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.0 billion for 2015 , $328 million for 2016 , and $221 million for 2017 , which includes expenditures related to the construction of the Kemper IGCC of $801 million in 2015 and $132 million in 2016. The amounts related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC for approximately $596 million (including construction costs for all prior periods relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $94 million, $25 million, and $35 million for 2015 , 2016 , and 2017 , respectively. These estimated amounts also include capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Integrated Coal Gasification Combined Cycle" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information and further risks related to the estimated schedule and costs and rate recovery for the Kemper IGCC.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in thousands)		
Long-term debt [(a)] —					
Principal	$ 775,000	$ 335,000	$ 125,000	$ 1,032,695	$ 2,267,695
Interest	77,715	132,442	120,904	723,455	1,054,516
Preferred stock dividends [(b)]	1,733	3,465	3,465	—	8,663
Financial derivative obligations [(c)]	26,270	18,623	536	—	45,429
Unrecognized tax benefits [(d)]	164,821	—	—	—	164,821
Operating leases [(e)]	3,950	2,601	—	—	6,551
Capital leases [(f)]	2,667	5,741	6,331	64,940	79,679
Purchase commitments —					
Capital [(g)]	1,016,215	491,886	—	—	1,508,101
Fuel [(h)]	266,934	299,888	255,396	289,215	1,111,433
Long-term service agreements [(i)]	27,109	23,367	20,596	128,832	199,904
Pension and other postretirement benefits plans [(j)]	6,187	13,112	—	—	19,299
Total	$ 2,368,601	$ 1,326,125	$ 532,228	$ 2,239,137	$ 6,466,091

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 10 to the financial statements.

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) Capital lease related to a 20-year nitrogen supply agreement for the Kemper IGCC. See Note 6 to the financial statements for additional information.

(g) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(h) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan , financing activities, completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water , CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, the pending EPA civil action, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards , including any PSC requirements and the requirements of tax credits and other incentives , and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans ;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between the Company and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;

- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2014 , 2013 , and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 794,643**	$ 799,139	$ 747,453
Wholesale revenues, non-affiliates	**322,659**	293,871	255,557
Wholesale revenues, affiliates	**107,210**	34,773	16,403
Other revenues	**18,099**	17,374	16,583
Total operating revenues	**1,242,611**	1,145,157	1,035,996
Operating Expenses:			
Fuel	**573,936**	491,250	411,226
Purchased power, non-affiliates	**17,848**	5,752	5,221
Purchased power, affiliates	**25,096**	42,579	49,907
Other operations and maintenance	**270,669**	253,329	228,675
Depreciation and amortization	**97,120**	91,398	86,510
Taxes other than income taxes	**79,112**	80,694	79,445
Estimated loss on Kemper IGCC	**868,000**	1,102,000	78,000
Total operating expenses	**1,931,781**	2,067,002	938,984
Operating Income (Loss)	**(689,170)**	(921,845)	97,012
Other Income and (Expense):			
Allowance for equity funds used during construction	**136,436**	121,629	64,793
Interest expense, net of amounts capitalized	**(45,322)**	(36,481)	(40,838)
Other income (expense), net	**(14,097)**	(6,030)	1,264
Total other income and (expense)	**77,017**	79,118	25,219
Earnings (Loss) Before Income Taxes	**(612,153)**	(842,727)	122,231
Income taxes (benefit)	**(285,205)**	(367,835)	20,556
Net Income (Loss)	**(326,948)**	(474,892)	101,675
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income (Loss) After Dividends on Preferred Stock	**$ (328,681)**	$ (476,625)	$ 99,942

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2014 , 2013 , and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Net Income (Loss)	**$ (326,948)**	$ (474,892)	$ 101,675
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(296) respectively	**—**	—	(479)
Reclassification adjustment for amounts included in net income, net of tax of $526, $526, and $411, respectively	**849**	849	663
Total other comprehensive income (loss)	**849**	849	184
Comprehensive Income (Loss)	**$ (326,099)**	$ (474,043)	$ 101,859

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014 , 2013 , and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income (loss)	$ **(326,948)**	$ (474,892)	$ 101,675
Adjustments to reconcile net income (loss) to net cash provided from operating activities —			
Depreciation and amortization, total	**104,422**	92,465	86,981
Deferred income taxes	**145,417**	(396,400)	17,688
Investment tax credits received	**(38,366)**	144,036	82,464
Allowance for equity funds used during construction	**(136,436)**	(121,629)	(64,793)
Pension, postretirement, and other employee benefits	**(28,899)**	13,953	(35,425)
Hedge settlements	**—**	—	(15,983)
Stock based compensation expense	**2,903**	2,510	2,084
Regulatory assets associated with Kemper IGCC	**(71,816)**	(35,220)	(15,445)
Estimated loss on Kemper IGCC	**868,000**	1,102,000	78,000
Kemper regulatory deferral	**—**	90,524	—
Other, net	**14,022**	14,585	10,516
Changes in certain current assets and liabilities —			
-Receivables	**(19,065)**	(25,001)	(6,589)
-Under recovered regulatory clause revenues	**(2,471)**	—	—
-Fossil fuel stock	**13,121**	63,093	(36,206)
-Materials and supplies	**(15,496)**	(11,087)	(3,473)
-Prepaid income taxes	**(50,457)**	16,644	(3,852)
-Other current assets	**(3,940)**	(4,363)	(19,851)
-Other accounts payable	**32,661**	12,693	8,814
-Accrued interest	**29,349**	16,768	17,627
-Accrued taxes	**39,392**	11,141	13,768
-Accrued compensation	**17,008**	(6,382)	(183)
-Over recovered regulatory clause revenues	**(17,826)**	(58,979)	16,836
-Mirror CWIP	**180,255**	—	—
-Other current liabilities	**(446)**	1,109	757
Net cash provided from operating activities	**734,384**	447,568	235,410
Investing Activities:			
Property additions	**(1,257,440)**	(1,640,782)	(1,620,047)
Investment in restricted cash	**(10,548)**	—	—
Distribution of restricted cash	**10,548**	—	—
Cost of removal net of salvage	**(13,418)**	(10,386)	(4,355)
Construction payables	**(49,532)**	(50,000)	78,961
Capital grant proceeds	**—**	4,500	13,372
Proceeds from asset sales	**—**	79,020	—
Other investing activities	**(19,217)**	14,903	(16,706)
Net cash used for investing activities	**(1,339,607)**	(1,602,745)	(1,548,775)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**451,387**	1,077,088	702,971
Bonds — Other	**22,866**	42,342	51,471
Senior notes issuances	**—**	—	600,000
Interest-bearing refundable deposit	**125,000**	—	150,000
Other long-term debt issuances	**470,000**	475,000	50,000
Redemptions —			

Bonds — Other		**(34,116)**		(82,563)		—
Capital Leases		**(2,539)**		(697)		(633)
Senior notes		**—**		(50,000)		(90,000)
Other long-term debt		**(220,000)**		(125,000)		(115,000)
Return of paid in capital		**(219,720)**		(104,804)		—
Payment of preferred stock dividends		**(1,733)**		(1,733)		(1,733)
Payment of common stock dividends		**—**		(71,956)		(106,800)
Other financing activities		**1,414**		(2,343)		6,512
Net cash provided from financing activities		**592,559**		1,155,334		1,246,788
Net Change in Cash and Cash Equivalents		**(12,664)**		157		(66,577)
Cash and Cash Equivalents at Beginning of Year		**145,165**		145,008		211,585
Cash and Cash Equivalents at End of Year	**$**	**132,501**	$	145,165	$	145,008
Supplemental Cash Flow Information:						
Cash paid (received) during the period for —						
Interest (net of $68,679, $54,118 and $32,816 capitalized, respectively)	**$**	**6,992**	$	20,285	$	32,589
Income taxes (net of refunds)		**(379,158)**		(134,198)		(77,580)
Noncash transactions —						
Accrued property additions at year-end		**114,469**		164,863		214,863
Capital lease obligation		**—**		82,915		—

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

Assets	**2014**	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 132,501**	$ 145,165
Receivables —		
Customer accounts receivable	**40,648**	40,978
Unbilled revenues	**35,494**	38,895
Under recovered regulatory clause revenues	**2,471**	—
Other accounts and notes receivable	**11,256**	4,600
Affiliated companies	**51,060**	34,920
Accumulated provision for uncollectible accounts	**(825)**	(3,018)
Fossil fuel stock, at average cost	**100,164**	113,285
Materials and supplies, at average cost	**61,582**	45,347
Other regulatory assets, current	**72,840**	48,583
Prepaid income taxes	**190,631**	34,751
Other current assets	**6,209**	9,357
Total current assets	**704,031**	512,863
Property, Plant, and Equipment:		
In service	**4,378,087**	3,458,770
Less accumulated provision for depreciation	**1,172,715**	1,095,352
Plant in service, net of depreciation	**3,205,372**	2,363,418
Construction work in progress	**2,160,646**	2,586,031
Total property, plant, and equipment	**5,366,018**	4,949,449
Other Property and Investments	**5,498**	4,857
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**225,507**	143,747
Other regulatory assets, deferred	**385,410**	200,620
Accumulated deferred income taxes	**17,388**	—
Other deferred charges and assets	**52,876**	36,673
Total deferred charges and other assets	**681,181**	381,040
Total Assets	**$ 6,756,728**	$ 5,848,209

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 777,667	$ 13,789
Interest-bearing refundable deposit	275,000	150,000
Accounts payable —		
Affiliated	85,882	70,299
Other	177,736	210,191
Customer deposits	14,970	14,379
Accrued taxes —		
Accrued income taxes	142,461	5,590
Other accrued taxes	83,686	77,958
Accrued interest	76,494	47,144
Accrued compensation	26,331	9,324
Other regulatory liabilities, current	2,164	14,480
Over recovered regulatory clause liabilities	532	18,358
Mirror CWIP	270,779	—
Other current liabilities	44,701	21,413
Total current liabilities	1,978,403	652,925
Long-Term Debt (See accompanying statements)	1,630,487	2,167,067
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	284,849	72,808
Deferred credits related to income taxes	9,370	10,191
Accumulated deferred investment tax credits	282,816	284,248
Employee benefit obligations	147,536	94,430
Asset retirement obligations	48,248	41,197
Other cost of removal obligations	165,999	156,683
Other regulatory liabilities, deferred	63,681	144,992
Other deferred credits and liabilities	28,299	14,337
Total deferred credits and other liabilities	1,030,798	818,886
Total Liabilities	4,639,688	3,638,878
Cumulative Redeemable Preferred Stock (See accompanying statements)	32,780	32,780
Common Stockholder's Equity (See accompanying statements)	2,084,260	2,176,551
Total Liabilities and Stockholder's Equity	$ 6,756,728	$ 5,848,209
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

	2014	2013	2014	2013
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	**$ 300,000**	$ 300,000		
5.60% due 2017	**35,000**	35,000		
5.55% due 2019	**125,000**	125,000		
1.63% to 5.40% due 2035-2042	**680,000**	680,000		
Adjustable rate (1.29% at 1/1/14) due 2014	**—**	11,250		
Adjustable rates (0.77% to 1.17% at 1/1/15) due 2015	**775,000**	525,000		
Total long-term notes payable	**1,915,000**	1,676,250		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	42,625		
Variable rates (0.02% to 0.06% at 1/1/15) due 2020-2028	**40,070**	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	**270,000**	270,000		
Total other long-term debt	**352,695**	352,695		
Capitalized lease obligations	**79,679**	82,217		
Unamortized debt premium	**62,701**	71,807		
Unamortized debt discount	**(1,921)**	(2,113)		
Total long-term debt (annual interest requirement — $78 million)	**2,408,154**	2,180,856		
Less amount due within one year	**777,667**	13,789		
Long-term debt excluding amount due within one year	**1,630,487**	2,167,067	**43.5%**	49.6%
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	**32,780**	32,780	**0.9**	0.7
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**2,612,136**	2,376,595		
Accumulated deficit	**(558,552)**	(229,871)		
Accumulated other comprehensive loss	**(7,015)**	(7,864)		
Total common stockholder's equity	**2,084,260**	2,176,551	**55.6**	49.7
Total Capitalization	**$ 3,747,527**	$ 4,376,398	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014 , 2013 , and 2012
Mississippi Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)		
Balance at December 31, 2011	1,121	$ 37,691	$ 694,855	$ 325,568	$ (8,897)	$ 1,049,217
Net income after dividends on preferred stock	—	—	—	99,942	—	99,942
Capital contributions from parent company	—	—	706,665	—	—	706,665
Other comprehensive income (loss)	—	—	—	—	184	184
Cash dividends on common stock	—	—	—	(106,800)	—	(106,800)
Balance at December 31, 2012	1,121	37,691	1,401,520	318,710	(8,713)	1,749,208
Net loss after dividends on preferred stock	—	—	—	(476,625)	—	(476,625)
Capital contributions from parent company	—	—	975,075	—	—	975,075
Other comprehensive income (loss)	—	—	—	—	849	849
Cash dividends on common stock	—	—	—	(71,956)	—	(71,956)
Balance at December 31, 2013	**1,121**	**37,691**	**2,376,595**	**(229,871)**	**(7,864)**	**2,176,551**
Net loss after dividends on preferred stock	**—**	**—**	**—**	**(328,681)**	**—**	**(328,681)**
Capital contributions from parent company	**—**	**—**	**235,541**	**—**	**—**	**235,541**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**849**	**849**
Balance at December 31, 2014	**1,121**	**$ 37,691**	**$ 2,612,136**	**$ (558,552)**	**$ (7,015)**	**$ 2,084,260**

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Mississippi Power Company 2014 Annual Report

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The Company is subject to regulation by the FERC and the Mississippi PSC. The Company follows GAAP in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $259.0 million , $205.0 million , and $212.7 million during 2014 , 2013 , and 2012 , respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $13.4 million , $12.5 million , and $11.7 million in 2014 , 2013 , and 2012 , respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $34.5 million , $27.1 million , and $28.1 million in 2014 , 2013 , and 2012 , respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $30.5 million , $16.5 million , and $21.2 million in 2014 , 2013 , and 2012 , respectively. See Note 4 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014 or 2013. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2014	2013	Note
		(in thousands)	
Retiree benefit plans – regulatory assets	**$ 169,317**	$ 82,799	(a,g)
Property damage	**(61,648)**	(60,092)	(i)
Deferred income tax charges	**222,599**	140,185	(c)
Property tax	**27,680**	31,206	(d)
Vacation pay	**11,172**	10,214	(e,g)
Loss on reacquired debt	**8,542**	9,178	(k)
Plant Daniel Units 3 and 4 regulatory assets	**23,013**	18,821	(j)
Other regulatory assets	**16,270**	5,415	(b)
Fuel-hedging (realized and unrealized) losses	**46,631**	10,340	(f,g)
Asset retirement obligations	**10,845**	8,918	(c)
Deferred income tax credits	**(9,370)**	(10,191)	(c)
Other cost of removal obligations	**(165,999)**	(156,683)	(c)
Kemper IGCC regulatory assets	**147,689**	75,873	(h)
Mirror CWIP / Kemper regulatory deferral	**(270,779)**	(90,524)	(h)
Other regulatory liabilities	**(4,198)**	(8,855)	(b)
Total regulatory assets (liabilities), net	**$ 171,764**	$ 66,604	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years . See Note 2 for additional information.

(b) Recorded and recovered (amortized) as approved by the Mississippi PSC.

(c) Asset retirement and removal assets and liabilities and deferred income tax assets are recovered, and removal assets and deferred income tax liabilities are amortized over the related property lives, which may range up to 49 years . Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(d) Recovered through the ad valorem tax adjustment clause over a 12 -month period beginning in April of the following year. See Note 3 under "Ad Valorem Tax Adjustment" for additional information.

(e) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the ECM.

(g) Not earning a return as offset in rate base by a corresponding asset or liability.

(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) For additional information, see Note 1 under "Provision for Property Damage."

(j) Deferred and amortized over a 10 -year period beginning October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term.

(k) Recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years .

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income any regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270.0 million of the Kemper IGCC through the DOE Grants funds. Through December 31, 2014 , the Company has received grant funds of $245.3 million , used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25 million is expected to be received for its initial operation. See Note 3 under "Kemper IGCC Schedule and Cost Estimate" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and projected amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery, ad valorem, and environmental factors annually.

The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 21.9% of the Company's total operating revenues in 2014 and are largely subject to rolling 10 -year cancellation notices.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

See Note 3 under "Retail Regulatory Matters" for additional information.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel costs also include gains and/or losses from fuel-hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of operations.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of CWIP is not allowed in rates.

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The Company's property, plant, and equipment in service consisted of the following at December 31:

	2014	2013
	(in thousands)	
Generation	$ 2,293,511	$ 1,475,264
Transmission	664,618	633,903
Distribution	853,835	828,470
General	484,711	439,721
Plant acquisition adjustment	81,412	81,412
Total plant in service	$ 4,378,087	$ 3,458,770

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses except for all costs associated with operating and maintaining the Kemper IGCC assets already placed in service and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause or charged to regulatory assets to be recovered through rates over the life of the assets starting after the Kemper plant is placed in service. In addition, the cost of maintenance, repairs, and replacement of minor items of property for Kemper IGCC assets in service, excluding the lignite mine, are deferred in regulatory assets. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2014 , 3.4% in 2013 , and 3.5% in 2012 . Depreciation studies are conducted periodically to update the composite rates. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities.

In January 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10 -year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. Depreciation associated with fixed assets, amortization associated with rolling stock, and depletion associated with minerals and minerals rights is recognized and charged to fuel stock and is expected to be recovered through the Company’s fuel clause. Depreciation associated with in-service Kemper IGCC-related assets has been deferred as a regulatory asset to be recovered over the life of the Kemper IGCC.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The Company has AROs related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified AROs related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the AROs related to these assets is indeterminable and, therefore, the fair value of the AROs cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of operations allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

Details of the ARO included in the balance sheets are as follows:

	2014	2013
	(in thousands)	
Balance at beginning of year	**$ 41,910**	$ 42,115
Liabilities settled	**(2,529)**	(24)
Accretion	**1,969**	1,840
Cash flow revisions	**6,898**	(2,021)
Balance at end of year	**$ 48,248**	$ 41,910

The increase in cash flow revisions in 2014 related to the Company's AROs associated with Watson landfill and Greene County asbestos.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain ; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $64 million and ongoing post-closure care of approximately $12 million . The Company will record AROs for the estimated closure costs required under the CCR Rule during 2015. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.91% , 6.89% , and 7.04% for the years ended December 31, 2014 , 2013 , and 2012 , respectively. AFUDC equity was $136.4 million , $121.6 million , and $64.8 million in 2014, 2013, and 2012, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. Every three years the Mississippi PSC, MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. In 2014 , 2013 , and 2012 , the Company made retail accruals of $3.3 million , $3.2 million , and $3.5 million , respectively. The Company accrued $0.3 million annually in 2014 , 2013 , and 2012 for the wholesale jurisdiction. As of December 31, 2014, the property damage reserve balances were $60.7 million and $1.0 million for retail and wholesale, respectively.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, mining, and generating plant materials. Materials are charged to inventory when purchased and then expensed, capitalized to plant, or charged to fuel stock, as appropriate, at weighted-average cost when utilized.

Fuel Inventory

Fuel inventory includes the average cost of coal, lignite, natural gas, oil, transportation and emissions allowances. Fuel is charged to inventory when purchased, except for the cost of owning and operating the lignite mine related to the Kemper IGCC which is charged to inventory as incurred, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates or capitalized as part of the Kemper IGCC costs if used for testing. The retail rate is approved by the Mississippi PSC and the wholesale rates are approved by the FERC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel-hedging program as discussed below result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Foreign currency exchange rate hedges are designated as fair value hedges. Settled foreign currency exchange hedges are recorded in CWIP. Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging instruments relating to the Kemper IGCC to a regulatory asset. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of operations. The amounts related to derivatives on the cash flow statement are classified in the same category as the items being hedged. See Note 10 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014 .

The Company has an ECM clause which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. For the year ended December 31, 2014 , the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $21.0 million and $23.6 million , respectively. For the year ended December 31, 2013, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21.0 million and $22.7 million , respectively. For the year ended December 31, 2012, the VIE consolidation resulted in an ARO and associated liability in the amounts of $21.0 million and $21.8 million , respectively. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014 , the Company voluntarily contributed $33 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015 . The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2015 , no other postretirement trust contributions are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.87% , respectively, and an annual salary increase of 3.84% .

	2014	2013	2012
Discount rate:			
Pension plans	**4.17%**	5.01%	4.26%
Other postretirement benefit plans	**4.03**	4.85	4.04
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**7.30**	7.04	6.96

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $30.2 million and $5.2 million , respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate is Reached**
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2014 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$ 6,241	$ (5,289)
Service and interest costs	250	(212)

Pension Plans

The total accumulated benefit obligation for the pension plans was $462 million at December 31, 2014 and $370 million at December 31, 2013 . Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 409,395	$ 432,553
Service cost	10,123	11,067
Interest cost	20,093	18,062
Benefits paid	(17,499)	(16,207)
Actuarial (gain) loss	90,735	(36,080)
Balance at end of year	512,847	409,395
Change in plan assets		
Fair value of plan assets at beginning of year	387,403	351,749
Actual return on plan assets	40,051	49,431
Employer contributions	35,526	2,430
Benefits paid	(17,499)	(16,207)
Fair value of plan assets at end of year	445,481	387,403
Accrued liability	$ (67,366)	$ (21,992)

At December 31, 2014 , the projected benefit obligations for the qualified and non-qualified pension plans were $481 million and $32 million , respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	$ —	$ 5,698
Other regulatory assets, deferred	150,972	77,572
Other current liabilities	(2,337)	(2,134)
Employee benefit obligations	(65,029)	(25,556)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2015 .

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	$ 3,030	$ 4,118	$ 1,088
Net (gain) loss	147,942	73,454	10,293
Regulatory assets	$ 150,972	$ 77,572	

NOTES (continued)
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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	$ 77,572	$ 146,838
Net (gain) loss	79,425	(58,662)
Reclassification adjustments:		
Amortization of prior service costs	(1,088)	(1,143)
Amortization of net gain (loss)	(4,937)	(9,461)
Total reclassification adjustments	(6,025)	(10,604)
Total change	73,400	(69,266)
Ending balance	$ 150,972	$ 77,572

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	$ 10,123	$ 11,067	$ 9,416
Interest cost	20,093	18,062	18,019
Expected return on plan assets	(28,742)	(26,849)	(24,121)
Recognized net (gain) loss	4,937	9,461	4,100
Net amortization	1,088	1,143	1,309
Net periodic pension cost	$ 7,499	$ 12,884	$ 8,723

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2014 , estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2015	$ 23,304
2016	19,551
2017	20,816
2018	21,905
2019	23,337
2020 to 2024	135,320

NOTES (continued)
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Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 80,940	$ 91,783
Service cost	1,025	1,151
Interest cost	3,812	3,619
Benefits paid	(4,887)	(4,080)
Actuarial (gain) loss	14,259	(11,959)
Retiree drug subsidy	506	426
Balance at end of year	95,655	80,940
Change in plan assets		
Fair value of plan assets at beginning of year	23,277	21,990
Actual return on plan assets	1,814	2,379
Employer contributions	3,413	2,562
Benefits paid	(4,381)	(3,654)
Fair value of plan assets at end of year	24,123	23,277
Accrued liability	$ (71,532)	$ (57,663)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	$ 18,345	$ 5,227
Other regulatory liabilities, deferred	(2,011)	(3,111)
Employee benefit obligations	(71,532)	(57,663)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2015 .

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	$ (2,123)	$ (2,311)	$ (188)
Net (gain) loss	18,457	4,427	778
Net regulatory assets	$ 16,334	$ 2,116	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 2,116**	$ 15,454
Net (gain) loss	**14,030**	(12,867)
Reclassification adjustments:		
Amortization of prior service costs	**188**	188
Amortization of net gain (loss)	**—**	(659)
Total reclassification adjustments	**188**	(471)
Total change	**14,218**	(13,338)
Ending balance	**$ 16,334**	$ 2,116

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	**$ 1,025**	$ 1,151	$ 1,038
Interest cost	**3,812**	3,619	4,155
Expected return on plan assets	**(1,585)**	(1,472)	(1,552)
Net amortization	**(188)**	471	470
Net periodic postretirement benefit cost	**$ 3,064**	$ 3,769	$ 4,111

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2015	$ 5,387	$ (512)	$ 4,875
2016	5,632	(566)	5,066
2017	5,911	(622)	5,289
2018	6,185	(680)	5,505
2019	6,475	(735)	5,740
2020 to 2024	34,139	(3,744)	30,395

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013 , along with the targeted mix of assets for each plan, is presented below:

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**24%**	25%
International equity	21	**19**	20
Domestic fixed income	37	**41**	38
Special situations	3	**1**	1
Real estate investments	11	**11**	11
Private equity	7	**4**	5
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2014 and 2013 . The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 78,344	$ 32,366	$ —	$ 110,710
International equity*	49,170	45,313	—	94,483
Fixed income:				
U.S. Treasury, government, and agency bonds	—	32,145	—	32,145
Mortgage- and asset-backed securities	—	8,646	—	8,646
Corporate bonds	—	52,185	—	52,185
Pooled funds	—	23,632	—	23,632
Cash equivalents and other	133	30,327	—	30,460
Real estate investments	13,479	—	51,520	64,999
Private equity	—	—	26,203	26,203
Total	$ 141,126	$ 224,614	$ 77,723	$ 443,463
Liabilities:				
Derivatives	$ (89)	$ —	$ —	$ (89)
Total	$ 141,037	$ 224,614	$ 77,723	$ 443,374

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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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 thousands)		
Assets:				
Domestic equity*	$ 63,558	$ 37,206	$ —	$ 100,764
International equity*	48,829	45,146	—	93,975
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,582	—	26,582
Mortgage- and asset-backed securities	—	6,904	—	6,904
Corporate bonds	—	43,420	—	43,420
Pooled funds	—	20,905	—	20,905
Cash equivalents and other	38	9,896	—	9,934
Real estate investments	11,546	—	44,341	55,887
Private equity	—	—	25,316	25,316
Total	$ 123,971	$ 190,059	$ 69,657	$ 383,687
Liabilities:				
Derivatives	$ —	$ (115)	$ —	$ (115)
Total	$ 123,971	$ 189,944	$ 69,657	$ 383,572

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014 Real Estate Investments	**2014** Private Equity	2013 Real Estate Investments	2013 Private Equity
		(in thousands)		
Beginning balance	**$ 44,341**	**$ 25,316**	$ 37,196	$ 26,240
Actual return on investments:				
Related to investments held at year end	**5,253**	**3,269**	3,385	378
Related to investments sold during the year	**1,525**	**(745)**	1,316	2,300
Total return on investments	**6,778**	**2,524**	4,701	2,678
Purchases, sales, and settlements	**401**	**(1,637)**	2,444	(3,602)
Ending balance	**$ 51,520**	**$ 26,203**	$ 44,341	$ 25,316

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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 thousands)		
Assets:				
Domestic equity*	$ 3,450	$ 1,425	$ —	$ 4,875
International equity*	2,165	1,997	—	4,162
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,279	—	5,279
Mortgage- and asset-backed securities	—	380	—	380
Corporate bonds	—	2,301	—	2,301
Pooled funds	—	1,041	—	1,041
Cash equivalents and other	589	1,337	—	1,926
Real estate investments	593	—	2,269	2,862
Private equity	—	—	1,154	1,154
Total	$ 6,797	$ 13,760	$ 3,423	$ 23,980
Liabilities:				
Derivatives	$ (5)	$ —	$ —	$ (5)
Total	$ 6,792	$ 13,760	$ 3,423	$ 23,975

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

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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 thousands)		
Assets:				
Domestic equity*	$ 3,089	$ 1,809	$ —	$ 4,898
International equity*	2,375	2,193	—	4,568
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,213	—	5,213
Mortgage- and asset-backed securities	—	337	—	337
Corporate bonds	—	2,109	—	2,109
Pooled funds	—	1,016	—	1,016
Cash equivalents and other	1	968	—	969
Real estate investments	560	—	2,156	2,716
Private equity	—	—	1,231	1,231
Total	$ 6,025	$ 13,645	$ 3,387	$ 23,057
Liabilities:				
Derivatives	$ —	$ (5)	$ —	$ (5)
Total	$ 6,025	$ 13,640	$ 3,387	$ 23,052

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014 Real Estate Investments	**2014** Private Equity	2013 Real Estate Investments	2013 Private Equity
		(in thousands)		
Beginning balance	**$ 2,156**	**$ 1,231**	$ 1,865	$ 1,293
Actual return on investments:				
Related to investments held at year end	**28**	**28**	158	18
Related to investments sold during the year	**67**	**(33)**	64	110
Total return on investments	**95**	**(5)**	222	128
Purchases, sales, and settlements	**18**	**(72)**	69	(190)
Ending balance	**$ 2,269**	**$ 1,154**	$ 2,156	$ 1,231

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014 , 2013 , and 2012 were $4.6 million , $4.1 million , and $3.9 million , respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Alabama Power (including claims involving a unit co-owned by the Company) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. In September 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Company and numerous other entities were designated by the Texas Commission on Environmental Quality (TCEQ) as potentially responsible parties at a site that was owned by an electric transformer company that handled the Company's transformers. The TCEQ approved the final site remediation plan in December 2013 and, on March 28, 2014, the impacted utilities, including the Company, agreed to commence remediation actions on the site. The Company's environmental remediation liability is $0.5 million as of December 31, 2014 and is expected to be recovered through the ECO Plan.

The final outcome of this matter cannot now be determined. However, based on the currently known conditions at this site and the nature and extent of activities relating to this site, the Company does not believe that additional liabilities, if any, at this site would be material to the financial statements.

FERC Matters

In 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provided that base rates under the cost-based electric tariff increase by approximately $22.6 million over a 12 -month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase was due to a change in the recovery methodology for the return on the Kemper IGCC CWIP. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

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Also in 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. Later in 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. In May 2013, the Company received an order from the FERC accepting the settlement agreement.

In April 2013, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the MRA cost-based electric tariff, which was accepted by the FERC in May 2013. The 2013 settlement agreement provided that base rates under the MRA cost-based electric tariff will increase by approximately $24.2 million annually, effective April 1, 2013.

On March 31, 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC on May 20, 2014, provides that base rates under the MRA cost-based electric tariff will increase approximately $10.1 million annually, with revised rates effective for services rendered beginning May 1, 2014.

Retail Regulatory Matters

General

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In March 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Energy Efficiency

In July 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were required to be filed within six months of the order and will be in effect for two to three years . An annual report addressing the performance of all energy efficiency programs is required.

On June 3, 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. On October 20, 2014, the Company filed a revised compliance filing, which proposed an increase of $6.7 million in retail revenues for the period December 2014 through December 2015. The Mississippi PSC approved the revised filing on November 4, 2014.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of the actual revenue requirement compared to the projected filing. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. I n May 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million . Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

In March 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9% , or $15.3 million , annually, effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 18, 2014, the Company submitted its annual PEP lookback filing for 2013, which indicated no surcharge or refund. On March 31, 2014, the Mississippi PSC suspended the filing to allow more time for review.

On June 3, 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

The ultimate outcome of these matters cannot be determined at this time.

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Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million , with the Company's portion being $330 million , excluding AFUDC. The Company's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project. As of December 31, 2014 , total project expenditures were $518.2 million , of which the Company's portion was $263.4 million , excluding AFUDC of $19.2 million .

In August 2013, the Mississippi PSC approved the Company’s 2013 ECO Plan filing which proposed no change in rates.

On August 1, 2014, the Company entered into a settlement agreement with the Sierra Club (Sierra Club Settlement Agreement) that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed the Sierra Club's appeal related to the CPCN to construct scrubbers on Plant Daniel Units 1 and 2.

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2014, $5.6 million of Plant Greene County costs and $2.0 million of costs related to Plant Watson have been reclassified as a regulatory asset. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2015 and 2016, respectively. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements. See "Other Matters – Sierra Club Settlement Agreement" herein for additional information.

The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; the most recent filing occurred on November 17, 2014. On January 13, 2015, the Mississippi PSC approved the 2015 retail fuel cost recovery factor, effective January 21, 2015. The retail fuel cost recovery factor will result in an annual increase of approximately $7.9 million . At December 31, 2014 , the amount of under-recovered retail fuel costs included in the balance sheets was $2.5 million compared to a $14.5 million over-recovered balance at December 31, 2013 .

The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2015, the wholesale MRA fuel rate decreased resulting in an annual decrease of $1.1 million . Effective February 1, 2015, the wholesale MB fuel rate decreased, resulting in an annual decrease of $0.1 million . At December 31, 2014 , the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $0.2 million compared to an over-recovered balance of $7.3 million at December 31, 2013 . At December 31, 2014 , the amount of over-recovered wholesale MB fuel costs included in the balance sheets was immaterial compared to an over-recovered balance of $0.3 million at December 31, 2013 . In addition, at December 31, 2014 , the amount of over-recovered MRA emissions allowance cost included in the balance sheets was $0.3 million compared to a $3.8 million under-recovered balance at December 31, 2013 . The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On May 6, 2014, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2014, in which the Company requested an annual rate increase of 0.38% , or $3.6 million in annual retail revenues, primarily due to an increase in property tax rates.

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. In the 2015 Mississippi Supreme Court (Court) decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and " – 2015 Mississippi Supreme Court Decision" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC .

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion , net of $245.3 million of DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , with recovery of prudently-incurred costs subject to approval by the Mississippi PSC.

The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

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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 the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions) and costs subject to the cost cap remain subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate [f]	Current Estimate	**Actual Costs at 12/31/2014**
		(in billions)	
Plant Subject to Cost Cap [a]	$ 2.40	$ 4.93	**$ 4.23**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.10**
AFUDC [b][c]	0.17	0.63	**0.45**
Combined Cycle and Related Assets Placed in Service – Incremental [d]	—	0.02	0.00
General Exceptions	0.05	0.10	**0.07**
Deferred Costs [c][e]	—	0.18	**0.12**
Total Kemper IGCC [a][c]	$ 2.97	$ 6.20	**$ 5.20**

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion , net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014 , $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 under "Retail Regulatory Matters – Baseload Act" for additional information. See "Investment Tax Credits and Bonus Depreciation" and "Section 174 Research and Experimental Deduction" herein for additional tax information related to the Kemper IGCC.

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements.

2013 Settlement Agreement

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that, among other things, established the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The 2013 Settlement Agreement also allowed the Company to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in February 2013. The Company's intent under the 2013 Settlement Agreement was to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact the Company's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC Rate Order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. For the period from March 2013 through December 31, 2014,

$257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service .

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC through the in-service date. The Company will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. The Company will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, the Company provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. The Company's analysis requested, among other things, confirmation of the Company's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, the Company's August 18, 2014 filing with the Mississippi PSC requested confirmation of the Company's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under the Company's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by the Company could have a material impact on the results of operations, financial condition, and liquidity of the Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, the Company had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. The Company is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying the Company's request for rehearing. The Company is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, the Company proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning in March 2013, was integral to the Rate Mitigation Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Rate Mitigation Plan, the Company proposed annual rate recovery to remain the same from 2014 through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of 2020, the Mississippi PSC would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" and "Investment Tax Credits and Bonus Depreciation" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or the Company withdraws the Rate Mitigation Plan, the Company would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion , the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and the Company is working to reach a mutually acceptable resolution. As a result of the Court's decision, the Company intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" for additional information.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

On August 18, 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million . The projected balance at March 31, 2016 is estimated to total approximately $269.8 million . The amortization period of 40 years proposed by the Company for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. The Company is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. The Company is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million .

See "2015 Mississippi Supreme Court Decision" for additional information.

See Note 1 under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, the Company executed a 40 -year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that the Company does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While the Company has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues and could have a material financial impact on the Company to the extent the Company is not able to enter into other similar contractual arrangements.

The ultimate outcome of these matters cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, the Company and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, the Company and SMEPA signed an amendment to the APA whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the 2011 power supply agreement were $16.7 million in 2014. In December 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, the Company and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) the Company agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified the Company that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, the Company received $150 million , $75 million , and $50 million , respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, the Company would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposit s.

The ultimate outcome of these matters cannot be determined at this time.

Investment Tax Credits and Bonus Depreciation

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. Through December 31, 2014, the Company had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210.0 million had been utilized through that date. These credits will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. The Company currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

The ultimate outcome of these matters cannot be determined at this time.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, the Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014 . See Note 5 under "Unrecognized Tax Benefits" for additional information.

Other Matters

Sierra Club Settlement Agreement

On August 1, 2014, the Company entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the scrubber project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.

Under the Sierra Club Settlement Agreement, the Company agreed to, among other things, fund a $15 million grant payable over a 15 -year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, the Company paid $7 million in 2014, recognized in other income (expense), net in the statement of operations. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.

In August 2014, a decision was made to cease coal operations at Greene County Steam Plant and convert to natural gas no later than April 16, 2016. As a result, active construction projects related to these assets were cancelled in September 2014. Associated amounts in CWIP of $5.6 million , reflecting the Company's share of the costs, were subsequently transferred to regulatory assets. See Note 3 under "Retail Regulatory Matters- Environmental Compliance Overview Plan" herein for additional information.

At December 31, 2014 , the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in thousands)	
Greene County				
Units 1 and 2	40%	$ 102,384	$ 51,911	$ 902
Daniel				
Units 1 and 2	50%	$ 299,440	$ 155,606	$ 286,240

The Company's proportionate share of plant operating expenses is included in the statements of operations and the Company is responsible for providing its own financing.

See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama and Mississippi. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in thousands)	
Federal —			
Current	**$ (431,077)**	$ 23,345	$ 1,212
Deferred	**183,461**	(342,870)	16,994
	(247,616)	(319,525)	18,206
State —			
Current	**455**	5,219	1,656
Deferred	**(38,044)**	(53,529)	694
	(37,589)	(48,310)	2,350
Total	**$ (285,205)**	$ (367,835)	$ 20,556

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 thousands)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 1,068,242**	$ 371,553
Property basis differences	**—**	130,679
ECM under recovered	**—**	1,777
Regulatory assets associated with AROs	**19,299**	16,764
Pensions and other benefits	**35,200**	23,769
Regulatory assets associated with employee benefit obligations	**67,727**	33,127
Regulatory assets associated with the Kemper IGCC	**61,561**	30,708
Rate differential	**89,040**	56,074
Federal effect of state deferred taxes	**1,279**	30,615
Fuel clause under recovered	**3,288**	—
Other	**52,215**	35,583
Total	**1,397,851**	730,649
Deferred tax assets —		
Fuel clause over recovered	**—**	7,741
Estimated loss on Kemper IGCC	**631,326**	472,000
Pension and other benefits	**92,232**	57,999
Property insurance	**24,315**	23,693
Premium on long-term debt	**20,694**	23,736
Unbilled fuel	**14,535**	12,136
AROs	**19,299**	16,764
Interest rate hedges	**4,544**	5,094
Kemper rate factor - regulatory liability retail	**108,312**	36,210
Property basis difference	**263,430**	—
ECM over recovered	**905**	—
Deferred state tax assets	**56,736**	—
Other	**15,111**	18,094
Total	**1,251,439**	673,467
Total deferred tax liabilities, net	**146,412**	57,182
Portion included in (accrued) prepaid income taxes, net	**121,049**	15,626
Deferred state tax asset	**17,388**	—
Accumulated deferred income taxes	**$ 284,849**	$ 72,808

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2014 , the tax-related regulatory assets were $226.2 million . These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2014 , the tax-related regulatory liabilities were $9.4 million . These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of operations. Credits for non-Kemper IGCC related deferred ITCs amortized in this manner amounted to $1.4 million , $1.2 million , and $1.2 million for 2014 , 2013 , and 2012 , respectively. At December 31, 2014 , all non-Kemper IGCC ITCs available to reduce federal income taxes payable had been utilized.

In 2010, the Company began recognizing ITCs associated with the construction expenditures related to the Kemper IGCC. At December 31, 2014 , the Company had $276.4 million in unamortized ITCs associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operation in accordance with the Internal Revenue Code. A portion of the tax credits will be subject to recapture upon successful completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2014	2013	2012
Federal statutory rate	**(35.0)%**	(35.0)%	35.0 %
State income tax, net of federal deduction	**(4.0)**	(3.7)	1.3
Non-deductible book depreciation	**0.1**	0.1	0.3
AFUDC-equity	**(7.8)**	(5.0)	(18.6)
Other	**0.1**	(0.1)	(1.2)
Effective income tax rate (benefit rate)	**(46.6)%**	(43.7)%	16.8 %

The increase in the Company's 2014 effective tax rate (benefit rate), as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity. The decrease in the Company's 2013 effective tax rate, as compared to 2012, is primarily due to an increase in the estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 3,840**	$ 5,755	$ 4,964
Tax positions from current periods	**58,148**	226	1,186
Tax positions from prior periods	**102,833**	(2,141)	(26)
Settlements with taxing authorities	**—**	—	(369)
Balance at end of year	**$ 164,821**	$ 3,840	$ 5,755

The increases in tax positions from current periods and prior periods for 2014 relate to deductions for R&E expenditures related to the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Section 174 Research and Experimental Deduction" for more information. The decrease in tax positions from prior periods for 2013 relates primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" below for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 4,341**	$ 3,840	$ 3,656
Tax positions not impacting the effective tax rate	**160,480**	—	2,099
Balance of unrecognized tax benefits	**$ 164,821**	$ 3,840	$ 5,755

The tax positions impacting the effective tax rate primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2014 relate to a deduction for R&E related to the Kemper IGCC. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2014	2013	2012
		(in thousands)	
Interest accrued at beginning of year	**$ 1,171**	$ 772	$ 680
Interest accrued during the year	**1,698**	399	92
Balance at end of year	**$ 2,869**	$ 1,171	$ 772

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Bank Term Loans

In January 2014, the Company entered into an 18 -month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company’s continuous construction program.

At December 31, 2014 and 2013 , the Company had $775 million and $525 million of bank loans outstanding, respectively, which are reflected in the statements of capitalization as securities due within one year and long-term debt.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014 , the Company was in compliance with its debt limits.

Senior Notes

At December 31, 2014 and 2013 , the Company had $1.1 billion of senior notes outstanding. These senior notes are effectively subordinated to the secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.

Plant Daniel Revenue Bonds

In 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor.

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These bonds are secured by Plant Daniel Units 3 and 4 and certain related personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million , reflecting a premium of $76.1 million .

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2014 and 2013 was as follows:

	2014	2013
	(in millions)	
Bank term loans	**$ 775.0**	$ —
Revenue bonds	**—**	11.3
Capitalized leases	**2.7**	2.5
Outstanding at December 31	**$ 777.7**	$ 13.8

Maturities through 2019 applicable to total long-term debt are as follows: $777.7 million in 2015, $302.8 million in 2016, $37.9 million in 2017, $3.1 million in 2018, and $128.2 million in 2019.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $82.7 million .

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of the Company. In November 2013, the MBFC issued $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013B for the benefit of the Company.

In May 2014 and August 2014, the MBFC issued $12.3 million and $10.5 million , respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of the Company and proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity. The Company had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2014 and 2013 . The Company had no obligation as of December 31, 2014 and $11.3 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013 . Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

The Company's agreements relating to the taxable revenue bonds include covenants limiting debt levels consistent with those described above under "Bank Term Loans."

Capital Leases

In September 2013, the Company entered into an agreement to sell the air separation unit for the Kemper IGCC and also entered into a 20 -year nitrogen supply agreement. The nitrogen supply agreement was determined to be a sale/leaseback agreement which resulted in a capital lease obligation at December 31, 2014 of $80.0 million with an annual interest rate of 4.9% . There are no contingent rentals in the contract and a portion of the monthly payment specified in the agreement is related to executory costs for the operation and maintenance of the air separation unit and excluded from the minimum lease payments. The minimum lease payments for 2014 were $6.5 million and will be $6.5 million each year thereafter. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

Other Obligations

In 2012, January 2014, and October 2014, the Company received $ 150 million , $75 million , and $50 million , respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014 , 9.932% per annum for 2013 , and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund.

In May 2014, the Company issued a 19 -month floating rate promissory note to Southern Company for a loan bearing interest based on one-month LIBOR. This loan was for $220 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's construction program. This loan was repaid in September 2014.

Assets Subject to Lien

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries.

Outstanding Classes of Capital Stock

The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2014 , committed credit arrangements with banks were as follows:

Expires				Executable Term-Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
		(in millions)					
$135	$165	$300	$300	$25	$40	$65	$70

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration.

Most of these bank credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of these bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities and any securitized debt relating to the securitization of certain costs of the Kemper IGCC.

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A portion of the $300 million unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $40.1 million .

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements.

At December 31, 2014 and 2013 , there was no short-term debt outstanding.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2014 , 2013 , and 2012 , the Company incurred fuel expense of $573.9 million , $491.3 million , and $411.2 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

Coal commitments include a management fee associated with a 40 -year management contract with Liberty Fuels related to the Kemper IGCC with the remaining amount as of December 31, 2014 of $38.4 million . Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $12.7 million , $10.1 million , and $11.1 million for 2014 , 2013 , and 2012 , respectively.

The Company and Gulf Power have jointly entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. The Company has one remaining operating lease which has 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.

The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $4.9 million in 2014 , $3.1 million in 2013 , and $3.6 million in 2012 . The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million . The Company has no lease obligations for the period 2018 and thereafter.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.2 million annually from 2012 through 2014. The Company's annual lease payment for 2015 is expected to be $0.1 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $7.5 million in 2014 , $6.7 million in 2013 , and $7.3 million in 2012 related to barges and tow/shift boats. The Company's annual lease payment for 2015 with respect to these barge transportation leases is expected to be $1.8 million .

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's system employees ranging from line management to executives. As of December 31, 2014 , there were 244 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014 , 2013 , and 2012 , employees of the Company were granted stock options for 578,256 shares, 345,830 shares, and 278,709 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 , 2013 , and 2012 , derived using the Black-Scholes stock option pricing model, was $2.20 , $2.93 , and $3.39 , respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014 , 2013 , and 2012 was $5.4 million , $2.7 million , and $4.9 million , respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.1 million , $1.1 million , and $1.9 million for the years ended December 31, 2014 , 2013 , and 2012 , respectively. As of December 31, 2014 , the aggregate intrinsic value for the options outstanding and options exercisable was $18.4 million and $12.3 million , respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three -year performance period which equates to the requisite service period. Employees that retire prior to the end of the three -year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three -year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014 , 2013 , and 2012 , employees of the Company were granted performance share units of 49,579 , 36,769 , and 33,077 , respectively. The weighted average grant-date fair value of performance share units granted during 2014 , 2013 , and 2012 , determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54 , $40.50 , and $41.99 , respectively.

The Company recognizes compensation expense on a straight-line basis over the three -year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014 , 2013 , and 2012 , total compensation cost for performance share units recognized in income was $1.7 million , $1.5 million , and $1.2 million , respectively, with the related tax benefit also recognized in income of $0.6 million , $0.6 million , and $0.4 million , respectively. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014 , there was $1.8 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months .

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

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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 thousands)		
Assets:				
Energy-related derivatives	$ —	$ 65	$ —	$ 65
Cash equivalents	114,900	—	—	114,900
Total	$ 114,900	$ 65	$ —	$ 114,965
Liabilities:				
Energy-related derivatives	$ —	$ 45,429	$ —	$ 45,429

As of December 31, 2013 , assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 4,803	$ —	$ 4,803
Cash equivalents	125,000	—	—	125,000
Total	$ 125,000	$ 4,803	$ —	$ 129,803
Liabilities:				
Energy-related derivatives	$ —	$ 10,281	$ —	$ 10,281
Foreign currency derivatives	—	1	—	1
Total	$ —	$ 10,282	$ —	$ 10,282

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for foreign currency derivatives are from observable market sources. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013 , the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in thousands)*			
Cash equivalents:				
Money market funds	$ 114,900	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$ 125,000	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2014	**$ 2,328,476**	**$ 2,382,050**
2013	$ 2,098,639	$ 2,045,519

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk and occasionally foreign currency risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of three methods:

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- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of operations in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of operations as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014 , the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
54	2018	—

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2014 , there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are $1.4 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Foreign Currency Derivatives

The Company may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings; however, the Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. During 2011, certain fair value hedges were de-designated and subsequently settled in 2012. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2014 , there were no foreign currency derivatives outstanding.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013 , the fair value of energy-related derivatives and foreign currency derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 30**	$ 3,352	Other current liabilities	**$ 26,259**	$ 3,652
	Other deferred charges and assets	**22**	1,451	Other deferred credits and liabilities	**19,159**	6,629
Total derivatives designated as hedging instruments for regulatory purposes		**$ 52**	$ 4,803		**$ 45,418**	$ 10,281
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Foreign currency derivatives:	Other current assets	**$ —**	$ —	Other current liabilities	**$ —**	$ 1
Total		**$ 52**	$ 4,803		**$ 45,418**	$ 10,282

Energy-related derivatives not designated as hedging instruments were immaterial for 2014 and 2013. The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

	Fair Value				
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in thousands)			*(in thousands)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 65**	$ 4,803	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 45,429**	$10,282
Gross amounts not offset in the Balance Sheet [(b)]	**(64)**	(3,856)	Gross amounts not offset in the Balance Sheet [(b)]	**(64)**	(3,856)
Net energy-related derivative assets	**$ 1**	$ 947	**Net energy-related derivative liabilities**	**$ 45,365**	$ 6,426

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.

(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

NOTES (continued)
Mississippi Power Company 2014 Annual Report

At December 31, 2014 and 2013 , the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (26,259)**	$ (3,652)	Other regulatory liabilities, current	**$ 30**	$ 3,352
	Other regulatory assets, deferred	**(19,159)**	(6,629)	Other regulatory liabilities, deferred	**22**	1,451
Total energy-related derivative gains (losses)		**$ (45,418)**	$ (10,281)		**$ 52**	$ 4,803

The pre-tax effects of unrealized gains (losses) arising from energy-related derivative instruments not designated as hedging instruments was immaterial for 2014 and 2013.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2014**	2013	2012	**Statements of Operations Location**	**2014**	2013	2012
		(in thousands)				*(in thousands)*	
Energy-related derivatives	**$ —**	$ —	$ —	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**—**	—	(774)	Interest Expense	**(1,375)**	(1,375)	(1,073)
Total	**$ —**	$ —	$ (774)		**$ (1,375)**	$ (1,375)	$ (1,073)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the years ended December 31, 2014 and 2013, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on the Company's statements of operations were immaterial. For the year ended December 31, 2012 , the pre-tax effect of foreign currency derivatives designated as fair value hedging instruments, which include a pretax loss associated with the de-designated hedges prior to de-designation, was a $ 0.6 million gain. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of operations.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014 , the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014 , the fair value of derivative liabilities with contingent features was $9.9 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

NOTES (continued)
Mississippi Power Company 2014 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in thousands)	
March 2014	**$ 331,161**	**$ (325,460)**	**$ (172,048)**
June 2014	**310,975**	**56,021**	**62,495**
September 2014	**354,623**	**(349,010)**	**(195,070)**
December 2014	**245,852**	**(70,721)**	**(24,058)**
March 2013	$ 245,934	$ (429,148)	$ (246,321)
June 2013	306,435	(388,395)	(219,110)
September 2013	325,206	(79,890)	(24,115)
December 2013	267,582	(24,412)	12,921

As a result of the revisions to the cost estimate for the Kemper IGCC, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, $462.0 million ($285.3 million after tax) in the first quarter 2013, and $78.0 million ($48.2 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2010 - 2014
Mississippi Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	**$ 1,242,611**	$ 1,145,157	$ 1,035,996	$ 1,112,877	$ 1,143,068
Net Income (Loss) After Dividends on Preferred Stock (in thousands)	**$ (328,681)**	$ (476,625)	$ 99,942	$ 94,182	$ 80,217
Cash Dividends on Common Stock (in thousands)	**$ —**	$ 71,956	$ 106,800	$ 75,500	$ 68,600
Return on Average Common Equity (percent)	**(15.43)**	(24.28)	7.14	10.54	11.49
Total Assets (in thousands)	**$ 6,756,728**	$ 5,848,209	$ 5,373,621	$ 3,671,842	$ 2,476,321
Gross Property Additions (in thousands)	**$ 1,388,711**	$ 1,773,332	$ 1,665,498	$ 1,205,704	$ 340,162
Capitalization (in thousands):					
Common stock equity	**$ 2,084,260**	$ 2,176,551	$ 1,749,208	$ 1,049,217	$ 737,368
Redeemable preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**1,630,487**	2,167,067	1,564,462	1,103,596	462,032
Total (excluding amounts due within one year)	**$ 3,747,527**	$ 4,376,398	$ 3,346,450	$ 2,185,593	$ 1,232,180
Capitalization Ratios (percent):					
Common stock equity	**55.6**	49.7	52.3	48.0	59.8
Redeemable preferred stock	**0.9**	0.7	1.0	1.5	2.7
Long-term debt	**43.5**	49.6	46.7	50.5	37.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**152,453**	152,585	152,265	151,805	151,944
Commercial	**33,496**	33,250	33,112	33,200	33,121
Industrial	**482**	480	472	496	504
Other	**175**	175	175	175	187
Total	**186,606**	186,490	186,024	185,676	185,756
Employees (year-end)	**1,478**	1,344	1,281	1,264	1,280

SELECTED FINANCIAL AND OPERATING DATA 2010 - 2014 (continued)
Mississippi Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	$ 239,330	$ 241,956	$ 226,847	$ 246,510	$ 256,994
Commercial	257,189	265,506	250,860	263,256	266,406
Industrial	290,902	289,272	262,978	275,752	267,588
Other	7,222	2,405	6,768	6,945	6,924
Total retail	794,643	799,139	747,453	792,463	797,912
Wholesale — non-affiliates	322,659	293,871	255,557	273,178	287,917
Wholesale — affiliates	107,210	34,773	16,403	30,417	41,614
Total revenues from sales of electricity	1,224,512	1,127,783	1,019,413	1,096,058	1,127,443
Other revenues	18,099	17,374	16,583	16,819	15,625
Total	$ 1,242,611	$ 1,145,157	$ 1,035,996	$ 1,112,877	$ 1,143,068
Kilowatt-Hour Sales (in thousands):					
Residential	2,126,115	2,087,704	2,045,999	2,162,419	2,296,157
Commercial	2,859,617	2,864,947	2,915,934	2,870,714	2,921,942
Industrial	4,942,689	4,738,714	4,701,681	4,586,356	4,466,560
Other	40,595	40,139	38,588	38,684	38,570
Total retail	9,969,016	9,731,504	9,702,202	9,658,173	9,723,229
Wholesale — non-affiliates	4,190,812	3,929,177	3,818,773	4,009,637	4,284,289
Wholesale — affiliates	2,899,814	931,153	571,908	648,772	774,375
Total	17,059,642	14,591,834	14,092,883	14,316,582	14,781,893
Average Revenue Per Kilowatt-Hour (cents)*:					
Residential	11.26	11.59	11.09	11.40	11.19
Commercial	8.99	9.27	8.60	9.17	9.12
Industrial	5.89	6.10	5.59	6.01	5.99
Total retail	7.97	8.21	7.70	8.21	8.21
Wholesale	6.06	6.76	6.19	6.52	6.51
Total sales	7.18	7.73	7.23	7.66	7.63
Residential Average Annual Kilowatt-Hour Use Per Customer	13,934	13,680	13,426	14,229	15,130
Residential Average Annual Revenue Per Customer	$ 1,568	$ 1,585	$ 1,489	$ 1,622	$ 1,693
Plant Nameplate Capacity Ratings (year-end) (megawatts)	3,867	3,088	3,088	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	2,618	2,083	2,168	2,618	2,792
Summer	2,345	2,352	2,435	2,462	2,638
Annual Load Factor (percent)	59.4	64.7	61.9	59.1	57.9
Plant Availability Fossil-Steam (percent)**	87.6	89.3	91.5	87.7	93.8
Source of Energy Supply (percent):					
Coal	39.7	32.7	22.8	34.9	43.0
Oil and gas	55.3	57.1	63.9	51.5	41.9
Purchased power —					
From non-affiliates	1.4	2.0	2.0	1.4	1.3
From affiliates	3.6	8.2	11.3	12.2	13.8
Total	100.0	100.0	100.0	100.0	100.0

* The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.
** Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

SOUTHERN POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2014 Annual Report

The management of Southern Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014 .

/s/ Oscar C. Harper, IV
Oscar C. Harper, IV
President and Chief Executive Officer

/s/ William C. Grantham
William C. Grantham
Vice President, Chief Financial Officer, and Treasurer

March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014 . These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-462 to II-484) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2014 and 2013 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 , in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
Adobe	Adobe Solar, LLC
Alabama Power	Alabama Power Company
AOCI	Accumulated other comprehensive income
Apex	Apex Nevada Solar, LLC
ASC	Accounting Standards Codification
Campo Verde	Campo Verde Solar, LLC
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
EMC	Electric Membership Corporation
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
First Solar	First Solar, Inc.
FPL	Florida Power & Light Company
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Imperial Valley	SG2 Imperial Valley, LLC
IRS	Internal Revenue Service
ITC	Investment tax credit
Kay Wind	Kay Wind, LLC
KWH	Kilowatt-hour
Macho Springs	Macho Springs Solar, LLC
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWH	Megawatt hour
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCE	Southern California Edison Company
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SG2 Holdings	SG2 Holdings, LLC
Southern Company system	The Southern Company, the traditional operating companies, Southern Power Company, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.

DEFINITIONS
(continued)

SRE	Southern Renewable Energy, Inc.
SRP	Southern Renewable Partnerships, LLC
STR	Southern Turner Renewable Energy, LLC
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
TRE	Turner Renewable Energy, LLC

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2014 Annual Report

OVERVIEW

Business Activities

Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term PPAs for the new facilities.

The Company and TRE, through STR, a jointly-owned subsidiary owned 90% by Southern Power Company, acquired all of the outstanding membership interests of Adobe and Macho Springs on April 17, 2014 and May 22, 2014, respectively. The two solar facilities began commercial operation in May 2014 with the approximate 20-MW Adobe solar photovoltaic facility serving a PPA with SCE through 2034 and the approximate 50-MW Macho Springs solar photovoltaic facility serving a PPA with EPE also through 2034.

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and at that time a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The entire output of the plant is contracted under a 25-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy (SDG&E).

See FUTURE EARNINGS POTENTIAL – "Acquisitions" herein and Note 2 to the financial statements for additional information.

As of December 31, 2014 , the Company had generating units totaling 9,074 MWs nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar facilities. The average remaining duration of the Company's wholesale contracts is approximately 10 years, which reduces remarketing risk. The Company's renewable assets, including biomass and solar, have contract coverage in excess of 20 years. Taking into account the PPAs and capacity from the Taylor County and Decatur County Solar Projects, as discussed in "FUTURE EARNINGS POTENTIAL – Construction Projects" herein, and the acquisition of Kay Wind, which is expected to close in the fourth quarter 2015, as discussed in "FUTURE EARNINGS POTENTIAL – Acquisitions" herein, the Company had an average of 77% of its available capacity covered for the next five years (through 2019) and an average of 70% of its available capacity covered for the next 10 years (through 2024). The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators, including peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (a low metric is optimal). Contract availability measures the percentage of scheduled hours delivered. Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2014 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2014 .

Earnings

The Company's 2014 net income was $172.3 million, a $6.8 million, or 4.1%, increase from 2013. The increase was primarily due to a decrease in income taxes primarily as a result of federal ITCs for new plants placed in service in 2014 and an increase in energy revenue from non-affiliates primarily related to new solar contracts. This increase was partially offset by increased depreciation, other operations and maintenance expenses, and interest expense.

The Company's 2013 net income was $165.5 million, a $9.8 million, or 5.6%, decrease from 2012. The decrease was primarily due to an increase in other operations and maintenance expenses and depreciation primarily due to an increase in costs related to scheduled outages and new plants placed in service, higher fuel and purchased power expenses, and higher interest expense. The decrease was partially offset by an increase in capacity and energy revenues from non-affiliates and lower income tax expense associated with the net impact of federal ITCs received in 2013.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	**2014**	2013
		(in millions)	
Operating revenues	**$ 1,501.2**	**$ 226.0**	$ 89.2
Fuel	**596.3**	**122.5**	47.5
Purchased power	**170.9**	**64.5**	13.1
Other operations and maintenance	**237.0**	**28.7**	35.2
Depreciation and amortization	**220.2**	**44.9**	32.7
Taxes other than income taxes	**21.5**	**0.1**	2.1
Total operating expenses	**1,245.9**	**260.7**	130.6
Operating income	**255.3**	**(34.7)**	(41.4)
Interest expense, net of amounts capitalized	**89.0**	**14.5**	12.0
Other income (expense), net	**5.6**	**9.7**	(3.1)
Income taxes (benefit)	**(3.2)**	**(49.1)**	(46.7)
Net income	**175.1**	**9.6**	(9.8)
Less: Net income attributable to noncontrolling interests	**2.8**	**2.8**	—
Net income attributable to Southern Power Company	**$ 172.3**	**$ 6.8**	$ (9.8)

Operating Revenues

Operating revenues for 2014 were $1.5 billion, reflecting a $226.0 million, or 17.7%, increase from 2013. Details of operating revenues are as follows:

	2014	2013	2012
		(in millions)	
Capacity revenues —			
Affiliates	**$ 117.8**	$ 126.0	$ 125.9
Non-affiliates	**428.4**	446.4	372.6
Total	**546.2**	572.4	498.5
Energy revenues —			
Affiliates	**35.4**	23.8	35.6
Non-affiliates	**602.2**	427.1	346.7
Total	**637.6**	450.9	382.3
Total PPA revenues	**1,183.8**	1,023.3	880.8
Revenues not covered by PPA	**314.6**	245.3	298.0
Other revenues	**2.8**	6.6	7.2
Total Operating Revenues	**$ 1,501.2**	$ 1,275.2	$ 1,186.0

The increase in operating revenues was primarily due to a $121.0 million increase in energy revenues under PPAs with non-affiliates, resulting from a 24.0% increase in KWH sales, primarily due to increased demand and customer scheduling, and a 69.6% increase in the average price of energy, primarily due to higher natural gas prices, as well as, a $54.6 million increase which was the result of new solar contracts served by Plants Adobe, Macho Springs, and Imperial Valley, which began in 2014, and Plants Campo Verde and Spectrum, which began in 2013. Also contributing to the increase was a $34.2 million increase in energy sales not covered by PPAs and a $33.3 million increase in sales under the Intercompany Interchange Contract (IIC), primarily due to increased generation and higher cost affiliate power. Additionally, there was an increase of $11.5 million in energy revenues under PPAs with affiliates primarily as a result of increased demand and customer scheduling. This increase was partially offset by an $18.0 million decrease in capacity revenues from non-affiliates primarily due to lower customer demand and the expiration of certain requirements contracts and an $8.1 million decrease in capacity revenues from affiliates primarily due to contract expirations.

Operating revenues in 2013 were $1.3 billion, an $89.2 million, or 7.5%, increase from 2012. The increase was primarily due to a $73.8 million increase in capacity revenues under PPAs with non-affiliates, resulting from a 10.6% increase in the total MWs of capacity under contract, primarily due to a new PPA served by Plant Nacogdoches, which began in June 2012, and an increase in capacity amounts under existing PPAs. Also contributing to the increase was an $80.4 million increase in energy sales under PPAs with non-affiliates, reflecting a 29.6% increase in the average price of energy and a $7.8 million increase related to new solar contracts, which began in 2013, served by Plants Campo Verde and Spectrum. This increase was partially offset by an $11.8 million decrease in energy sales under PPAs with affiliates, reflecting a 48.1% decrease in KWH sales primarily due to lower demand, partially offset by a 28.9% increase in the average price of energy. The increase in energy revenues from PPAs was partially offset by a $52.4 million decrease in energy sales not covered by PPAs, reflecting a 30.5% decrease in KWH sales primarily due to lower demand, partially offset by an 18.6% increase in the average price of energy.

Wholesale revenues from sales to affiliate companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC.

Wholesale revenues from sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" below for additional information regarding the Company's PPAs.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's fuel and purchased power expenditures are as follows:

	2014	2013	2012
		(in millions)	
Fuel	**$ 596.3**	$ 473.8	$ 426.3
Purchased power-non-affiliates	**104.9**	76.0	80.4
Purchased power-affiliates	**66.0**	30.4	12.9
Total fuel and purchased power expenses	**$ 767.2**	$ 580.2	$ 519.6

The Company's PPAs for natural gas-fired generation generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel cost is generally accompanied by an increase or decrease in related fuel revenue and does not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the Southern Company system power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by Southern Power Company, affiliate-owned generation, or external purchases.

In 2014, total fuel and purchased power expenses increased $187.0 million, or 32.2%, compared to 2013, primarily due to a 19.7% increase in the average cost of natural gas and a 24.0% increase in the average cost of purchased power. The increase reflected a 29.6% increase in the volume of KWHs purchased primarily as a result of higher demand and the availability of lower cost affiliate power.

In 2013, total fuel and purchased power expenses increased $60.6 million, or 11.7%, compared to 2012, primarily due to a 28.8% increase in the average cost of natural gas and a 21.1% increase in the average cost of purchased power. The increase was partially offset by a 12.8% net decrease in the volume of KWHs generated and purchased primarily due to lower demand and the availability of lower cost affiliate power.

In 2014, fuel expense increased $122.5 million, or 25.9%, compared to 2013. The increase was primarily due to a $91.3 million increase associated with the average cost of natural gas per KWH generated as well as a $31.2 million increase associated with the volume of KWHs generated.

In 2013, fuel expense increased $47.5 million, or 11.2%, compared to 2012. The increase was primarily due to a $104.1 million increase associated with the average cost of natural gas per KWH generated, partially offset by a $58.5 million decrease associated with the volume of KWHs generated.

In 2014, purchased power expense increased $64.5 million, or 60.6%, compared to 2013. The increase was primarily due to a $33.0 million increase associated with the average cost of purchased power and a $31.5 million increase associated with the volume of KWHs purchased.

In 2013, purchased power expense increased $13.1 million, or 14.0%, compared to 2012. The increase was primarily due to an $18.3 million increase associated with the average cost of purchased power, partially offset by a $5.3 million decrease associated with the volume of KWHs purchased.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $28.7 million, or 13.8%, compared to 2013. The increase was primarily due to a $10.6 million increase in other generation expenses primarily related to labor and repairs as well as a $7.8 million increase primarily as a result of increased business development costs and support services. Also contributing to the increase was a $6.6 million increase in costs related to new plants placed in service, including Plants Spectrum and Campo Verde in 2013, and Plants Adobe, Macho Springs and Imperial Valley in 2014, and a $2.2 million increase in employee compensation.

In 2013, other operations and maintenance expenses increased $35.2 million, or 20.4%, compared to 2012. The increase was primarily due to a $21.8 million increase related to scheduled outage costs at Plants Franklin and Wansley, $6.2 million in additional costs related to new plant additions, including Plants Nacogdoches, Apex, Granville, and Cleveland in 2012 and Plants Spectrum and Campo Verde in 2013, and a $1.4 million increase in transmission costs.

Depreciation and Amortization

In 2014, depreciation and amortization increased $44.9 million, or 25.6%, compared to 2013. The increase was primarily due to a $25.2 million increase in depreciation resulting from an increase in plant in service, including the addition of Plants Spectrum and Campo Verde in 2013, and Plants Adobe, Macho Springs, and Imperial Valley in 2014, an $8.4 million increase related to equipment retirements resulting from accelerated outage work, and a $5.9 million increase in component depreciation resulting from increased production at gas-fired plants.

In 2013, depreciation and amortization increased $32.7 million, or 22.9%, compared to 2012. The increase was primarily due to a $23.8 million increase in depreciation resulting from an increase in plant in service, including the additions of Plants Nacogdoches, Apex, Granville, and Cleveland in 2012 and Plants Spectrum and Campo Verde in 2013, a $3.5 million increase for outage related capital costs, and a $2.4 million increase resulting from higher depreciation rates driven by major outages occurring in 2013.

See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates and change to component depreciation. See also Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2014, interest expense, net of amounts capitalized increased $14.5 million, or 19.5%, compared to 2013. The increase was primarily due to a $9.3 million decrease in capitalized interest resulting from the completion of Plants Spectrum and Campo Verde in 2013 and an increase of $5.1 million in interest expense related to senior notes.

In 2013, interest expense, net of amounts capitalized increased $12.0 million, or 19.2%, compared to 2012. The increase was primarily due to a $19.1 million decrease in capitalized interest resulting from the completion of Plants Nacogdoches and

Cleveland in 2012, partially offset by a $9.2 million increase in capitalized interest associated with the construction of Plants Spectrum and Campo Verde in 2013.

Other Income (Expense), Net

In 2014, other income (expense), net increased $9.7 million compared to 2013. The increase in 2014 was primarily due to the recognition of a bargain purchase gain arising from a solar acquisition. Additionally, net income attributable to noncontrolling interests of approximately $3.9 million was included in other income (expense), net in 2013. See Note 10 to the financial statements for additional information on noncontrolling interests.

In 2013, other income (expense), net decreased $3.1 million compared to 2012. The decrease in 2013 was primarily due to increased earnings of STR, which resulted in a larger allocation of earnings to noncontrolling interest.

Income Taxes (Benefit)

In 2014, income taxes (benefit) decreased $49.1 million, or 107.0%, compared to 2013. The decrease was primarily due to a $20.1 million increase in tax benefits primarily from federal ITCs for solar plants placed in service in 2014, a $19.9 million decrease associated with lower pre-tax earnings, and a $10.5 million reduction in deferred income taxes as a result of the impact of state apportionment changes and beneficial changes in certain state income tax laws.

In 2013, income taxes (benefit) decreased $46.7 million, or 50.4%, compared to 2012. The decrease was primarily due to a $24.2 million increase in tax benefits from federal ITCs for solar plants placed in service in 2013 and a $20.9 million decrease associated with lower pre-tax earnings.

See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's market areas; the successful remarketing of capacity as current contracts expire; and the Company's ability to execute its acquisition and value creation strategy, including successfully expanding investments in renewable energy projects, and to construct generating facilities, including the impact of ITCs.

Other factors that could influence future earnings include weather, demand, cost of generating units within the power pool, and operational limitations.

Power Sales Agreements

The Company's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

The Company has assumed or entered into PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and an energy marketing firm. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return.

However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

As a general matter, substantially all of the Company's PPAs (excluding solar) provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

The Company's solar sales are also through long-term PPAs where the customer purchases the entire energy output of a dedicated solar facility.

Capacity charges that form part of the PPA payments (excluding solar) are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, to reduce the Company's exposure to certain operation and maintenance costs, it has long-term service agreements (LTSA) with General Electric International, Inc., Siemens Electric, Inc., First Solar, and NVT Licenses, LLC relating to such vendors' applicable equipment.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company is working to maintain and expand its share of the wholesale market. The Company expects that additional demand for capacity will begin to develop within some of its market areas beginning in the 2015-2017 timeframe. Taking into account the PPAs and capacity from the Taylor County and Decatur County Solar Projects, as discussed in "Construction Projects" herein, and the acquisition of Kay Wind, which is expected to close in the fourth quarter 2015, as discussed in "Acquisitions" herein, the Company had an average of 77% of its available capacity covered for the next five years (through 2019) and an average of 70% of its available capacity covered for the next 10 years (through 2024).

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the potential presence of wetlands or threatened and endangered species, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Environmental Statutes and Regulations

Air Quality

Each of the states in which the Company has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama, Florida, Georgia, and North Carolina) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of CSAPR, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in additional compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants . The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

These proposed and final water quality regulations could result in additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 9 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 11 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Income Tax Matters

Tax Credits

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. In January 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014. The current law provides for a 30% federal ITC for solar facilities placed in service through 2016 and, unless extended, will adjust to 10% for solar facilities placed in service thereafter. The Company qualified for ITCs related to Plants Adobe, Apex, Campo Verde, Cimarron, Granville, Imperial Valley, Macho Springs, Nacogdoches, and Spectrum, which have had and will continue to have a material impact on cash flows and net income. On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA extended the production tax credit for wind and certain other renewable sources of electricity to facilities for which construction had commenced by the end of 2014. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Bonus Depreciation

The TIPA additionally extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation will have a positive impact on the Company's cash flows, of approximately $110 million.

Acquisitions

Adobe Solar, LLC

On April 17, 2014, the Company and TRE, through STR, a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Adobe from Sun Edison, LLC, the original developer of the project. Adobe constructed and owns an approximately 20-MW solar generating facility in Kern County, California. The solar facility began commercial operation on May 21, 2014 and the entire output of the plant is contracted under a 20-year PPA with SCE. See Note 2 to the financial statements for additional information.

Macho Springs Solar, LLC

On May 22, 2014, the Company and TRE, through STR, acquired all of the outstanding membership interests of Macho Springs from First Solar Development, LLC, the original developer of the project. Macho Springs constructed and owns an approximately 50-MW solar photovoltaic facility in Luna County, New Mexico. The solar facility began commercial operation on May 23, 2014 and the entire output of the plant is contracted under a 20-year PPA with EPE. See Note 2 to the financial statements for additional information.

SG2 Imperial Valley, LLC

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and the entire output of the plant is contracted under a 25-year PPA with SDG&E.

In connection with this acquisition, at substantial completion, on November 26, 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. Ultimately, the Company indirectly owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to this transaction. See Note 2 to the financial statements for additional information.

Kay County Wind Facility

On February 24, 2015, the Company, through its wholly-owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind for approximately $492 million, with potential purchase price adjustments based on performance testing. Kay Wind is constructing an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015, and the entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is expected to close in the fourth quarter 2015 subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. See Note 2 to the financial statements for additional information.

Construction Projects

Taylor County Solar Project

On December 17, 2014, the Company announced that it will build an approximately 131-MW solar photovoltaic facility in Taylor County, Georgia. Construction of the facility is expected to begin in September 2015. Commercial operation is scheduled to begin in the fourth quarter of 2016, and the entire output of the facility is contracted under separate 25-year PPAs with Cobb Electric Membership Corp., Flint Electric Membership Corp., and Sawnee Electric Membership Corp. The total estimated cost of the facility is expected to be between $230 million and $250 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Decatur County Solar Projects

In February 2015, the Company announced that it will build two solar photovoltaic facilities, the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80-MW and 19-MW, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015, and the entire output of each project is contracted to Georgia Power. The output of the Decatur Parkway Solar Project is contracted under a 25-year PPA with Georgia Power and the entire output of the Decatur County Solar Project is contracted under a separate 20-year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million, which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of the Company's power sales contracts classified as leases are accounted for as operating leases and the associated lease revenue is recognized on a straight-line basis over the term of the contract. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed.

Non-Derivative and Normal Sale Derivative Transactions

If the power sales contract is not classified as a lease, the Company further considers the following factors to determine proper classification:

- Assessing whether the contract meets the definition of a derivative;
- Assessing whether the contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are accounted for as executory contracts. The related capacity revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Energy revenues are recognized in the period the energy is delivered or the service is rendered. Revenues are recorded on a gross basis in accordance with GAAP. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are accounted for on a fair value basis and are recorded in AOCI over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

Mark-to-Market Transactions

Contracts for sales of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are accounted for on a fair value basis and are recorded in net income.

Impairment of Long Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets consist of acquired PPAs from certain acquisitions that are amortized over the term of the respective PPAs, and goodwill resulting from certain acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations. Accordingly, the Company includes these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.

Depreciation

Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets determined by management. Certain generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 35 to 45 years. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes that could have a material impact on net income in the near term.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation on the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives determined by management.

Investment Tax Credits

Under the ARRA and ATRA, certain construction costs related to renewable generating assets are eligible for federal ITCs. A high degree of judgment is required in determining which construction expenditures qualify for federal ITCs. See Note 1 to the financial statements under "Income and Other Taxes" for additional information.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014 . The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $602.4 million in 2014. Net cash provided from operating activities totaled $604.4 million in 2013, an increase of $31.2 million compared to 2012. This increase was primarily due to an increase in cash received from federal ITCs.

Net cash used for investing activities totaled $813.7 million, $696.0 million, and $332.5 million in 2014, 2013, and 2012, respectively. Net cash used for investing activities in 2014 was primarily due to the Adobe, Macho Springs, and Imperial Valley acquisitions. Net cash used for investing activities in 2013 was primarily due to the Campo Verde acquisition and the construction of the Spectrum and Campo Verde solar facilities. Net cash used for investing activities in 2012 was primarily due to the Apex, Spectrum, and Granville acquisitions, construction of Plants Nacogdoches and Cleveland, and payments pursuant to LTSAs.

Net cash provided from financing activities totaled $217.2 million and $131.8 million in 2014 and 2013, respectively. Net cash used for financing activities totaled $229.0 million in 2012. Net cash provided from financing activities in 2014 was primarily due to the issuance of commercial paper. Net cash provided from financing activities in 2013 was primarily the result of the issuance of new senior notes. Net cash used for financing activities in 2012 was primarily due to payment of common stock dividends and a decrease in notes payable.

Significant asset changes in the balance sheet during 2014 included an increase in property, plant, and equipment, primarily due to the acquisition of Adobe, Macho Springs, and Imperial Valley and an increase in deferred income taxes, current, due to the carryforward of federal ITCs arising from certain solar acquisitions.

Significant liability and stockholder's equity changes in the balance sheet during 2014 included an increase in federal ITCs due to new solar facilities placed in service, including Adobe, Macho Springs, and Imperial Valley and an increase in deferred income taxes primarily due to bonus depreciation on those new solar facilities, and an increase in notes payable due to the issuance of commercial paper.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, securities issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

The issuance of securities by Southern Power Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Power Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

As of December 31, 2014, the Company's current liabilities exceeded current assets by $320.1 million due to the long-term debt maturing in 2015 and the use of short-term debt as a funding source, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. In 2015, the Company expects to utilize the capital markets and commercial paper markets as the source of funds for the majority of its maturities.

To meet liquidity and capital resource requirements, the Company had at December 31, 2014 cash and cash equivalents of approximately $74.6 million and Southern Power Company had a committed credit facility of $500 million (Facility) expiring in

2018. As of December 31, 2014 , the total amount available under the Facility was $488 million. The Facility does not contain a material adverse change clause applicable to borrowing. Subject to applicable market conditions, Southern Power Company plans to renew the Facility prior to its expiration.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to indebtedness of the Company. Southern Power Company is currently in compliance with all covenants in the Facility.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2014	**$ 195**	**0.4%**	**$ 54**	**0.4%**	**$ 445**
December 31, 2013	$ —	N/A	$ 117	0.4%	$ 271
December 31, 2012	$ 71	0.5%	$ 170	0.5%	$ 309

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014 , 2013 , and 2012 .

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility, and cash.

Financing Activities

During 2014 , the Company prepaid $9.5 million of long-term debt payable to TRE and issued $0.1 million due June 15, 2032, $0.8 million due April 30, 2033, $3.9 million due April 30, 2034, and $5.4 million due May 31, 2034 under promissory notes payable to TRE related to the financing of Apex, Campo Verde, Adobe, and Macho Springs, respectively.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.

The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	301
Below BBB- and/or Baa3	1,019

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

At December 31, 2014 , the Company had $18.8 million of long-term variable rate debt outstanding. The effect on annualized interest expense related to variable interest rate exposure if the Company sustained a 100 basis point change in interest rates is immaterial. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts associated with both power and natural gas positions, none of which are designated as hedges, for the years ended December 31 were as follows:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ —**	$ 0.8
Contracts realized or settled	**0.6**	(0.8)
Current period changes [(a)]	**1.3**	—
Contracts outstanding at the end of the period, assets (liabilities), net	**$ 1.9**	$ —

(a) Current period changes also include changes in the fair value of new contracts entered into during the period, if any.

The changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

	December 31, 2014	December 31, 2013
Power – net purchased or (sold)		
MWH (in millions)	**(0.5)**	0.2
Weighted average contract cost per MWH above (below) market prices (in dollars)	**$ 11.32**	$ (2.22)
Natural gas net purchased		
Commodity – mmBtu	**3.4**	1.6
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$ 1.02**	$ (0.08)

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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At December 31, 2014 , the net fair value of energy-related derivative contracts that were not designated as hedging instruments was $1.9 million. For the Company's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were not material for any year presented. This third party hedging activity was discontinued prior to the end of 2014.

Gains and losses on energy-related derivatives designated as cash flow hedges which are used by the Company to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transactions are reflected in earnings. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 8 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	1.9	1.9	—	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 1.9	$ 1.9	$ —	$ —

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $1.4 billion for 2015 , $1.3 billion for 2016 , and $407.0 million for 2017 . The construction program is subject to periodic review and revision. These amounts include estimates for potential plant acquisitions and new construction. In addition, the construction program includes capital improvements and work to be performed under LTSAs. Planned expenditures for plant acquisitions may vary materially due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, pursuant to an agreement with TRE, on or after November 25, 2015, or earlier in the event of the death of the controlling member of TRE, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in millions)		
Long-term debt [(a)] —					
Principal	$ 525.3	$ —	$ —	$ 1,093.8	$ 1,619.1
Interest	72.5	117.4	117.4	1,238.1	1,545.4
Financial derivative obligations [(b)]	3.5	0.1	—	—	3.6
Operating leases [(c)]	4.5	9.1	9.3	157.2	180.1
Unrecognized tax benefits [(d)]	4.7	—	—	—	4.7
Purchase commitments —					
Capital [(e)]	1,306.0	1,546.0	—	—	2,852.0
Fuel [(f)]	367.2	625.0	572.4	183.2	1,747.8
Purchased power [(g)]	53.5	77.4	80.5	83.8	295.2
Other [(h)]	52.9	226.7	158.8	560.4	998.8
Transmission agreements [(i)]	7.9	15.0	6.8	—	29.7
Total	$ 2,398.0	$ 2,616.7	$ 945.2	$ 3,316.5	$ 9,276.4

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) Operating lease commitments for the Plant Stanton Unit A land lease are subject to annual price escalation based on the Consumer Price Index for All Urban Consumers.

(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three year period. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs. See Note (h) below.

(f) Primarily includes commitments to purchase, transport, and store natural gas fuel. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014 .

(g) Purchased power commitments of $37.6 million in 2015, $77.4 million in 2016-2017, $80.5 million in 2018-2019, and $83.8 million after 2019 will be resold under a third party agreement at cost.

(h) Includes LTSAs, capital leases, and operation and maintenance agreements. LTSAs include price escalation based on inflation indices.

(i) Transmission commitments are based on Southern Company's current tariff rate for point-to-point transmission.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, customer growth, economic recovery, fuel and environmental cost recovery , current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, financing activities, estimated sales and purchases under power sale and purchase agreements, timing of expected future capacity need in existing markets, completion of acquisitions and construction projects, filings with federal regulatory authorities, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water and emissions of sulfur, nitrogen, CO_2 , soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards , including the requirements of tax credits and other incentives ;
- advances in technology;
- state and federal rate regulations ;
- the ability to successfully operate generating facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general ;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and

- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Wholesale revenues, non-affiliates	$ 1,115,880	$ 922,811	$ 753,653
Wholesale revenues, affiliates	382,523	345,799	425,180
Other revenues	2,846	6,616	7,215
Total operating revenues	1,501,249	1,275,226	1,186,048
Operating Expenses:			
Fuel	596,319	473,805	426,257
Purchased power, non-affiliates	104,871	75,954	80,438
Purchased power, affiliates	66,033	30,415	12,915
Other operations and maintenance	237,061	208,366	173,074
Depreciation and amortization	220,174	175,295	142,624
Taxes other than income taxes	21,512	21,416	19,309
Total operating expenses	1,245,970	985,251	854,617
Operating Income	255,279	289,975	331,431
Other Income and (Expense):			
Interest expense, net of amounts capitalized	(88,992)	(74,475)	(62,503)
Other income (expense), net	5,560	(4,072)	(1,022)
Total other income and (expense)	(83,432)	(78,547)	(63,525)
Earnings Before Income Taxes	171,847	211,428	267,906
Income taxes (benefit)	(3,228)	45,895	92,621
Net Income	175,075	165,533	175,285
Less: Net income attributable to noncontrolling interests	2,775	—	—
Net Income Attributable to Southern Power Company	$ 172,300	$ 165,533	$ 175,285

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014 , 2013 , and 2012
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	2014	2013	2012
		(in thousands)	
Net Income	**$ 175,075**	$ 165,533	$ 175,285
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(90), respectively	**—**	—	(136)
Reclassification adjustment for amounts included in net income, net of tax of $169, $2,357, and $3,919, respectively	**367**	3,695	6,189
Total other comprehensive income	**367**	3,695	6,053
Less: Comprehensive income attributable to noncontrolling interests	**2,775**	—	—
Comprehensive Income Attributable to Southern Power Company	**$ 172,667**	$ 169,228	$ 181,338

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014 , 2013 , and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income	**$ 175,075**	$ 165,533	$ 175,285
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization	**225,234**	183,239	156,268
Deferred income taxes	**(168,110)**	171,301	228,780
Investment tax credits	**73,512**	158,096	45,047
Amortization of investment tax credits	**(11,399)**	(5,535)	(2,633)
Deferred revenues	**(20,860)**	(18,477)	(12,633)
Mark-to-market adjustments	**(1,894)**	850	(9,275)
Other, net	**11,629**	3,335	3,104
Changes in certain current assets and liabilities —			
-Receivables	**(25,596)**	(11,178)	(1,384)
-Fossil fuel stock	**(2,576)**	2,438	(8,578)
-Materials and supplies	**(3,613)**	(8,410)	(7,825)
-Prepaid income taxes	**35,284**	(29,609)	(3,223)
-Other current assets	**(1,822)**	(2,219)	(1,624)
-Accounts payable	**30,352**	(11,572)	10,514
-Accrued taxes	**284,348**	(299)	431
-Accrued interest	**1,166**	6,093	385
-Other current liabilities	**1,646**	777	492
Net cash provided from operating activities	**602,376**	604,363	573,131
Investing Activities:			
Property additions	**(20,566)**	(500,756)	(116,633)
Cash paid for acquisitions	**(730,509)**	(132,163)	(124,059)
Change in construction payables	**(279)**	(4,072)	(27,387)
Payments pursuant to long-term service agreements	**(60,554)**	(57,269)	(63,932)
Other investing activities	**(1,756)**	(1,725)	(446)
Net cash used for investing activities	**(813,664)**	(695,985)	(332,457)
Financing Activities:			
Increase (decrease) in notes payable, net	**194,917**	(70,968)	(108,552)
Proceeds —			
Capital contributions	**146,356**	1,487	(662)
Senior notes	**—**	300,000	—
Other long-term debt	**10,253**	23,583	5,470
Redemptions — Other long-term debt	**(9,513)**	(9,284)	(2,450)
Distributions to noncontrolling interests	**(1,089)**	(506)	—
Capital contributions from noncontrolling interests	**7,531**	17,328	3,400
Payment of common stock dividends	**(131,120)**	(129,120)	(127,000)
Other financing activities	**(185)**	(746)	769
Net cash provided from (used for) financing activities	**217,150**	131,774	(229,025)
Net Change in Cash and Cash Equivalents	**5,862**	40,152	11,649
Cash and Cash Equivalents at Beginning of Year	**68,744**	28,592	16,943
Cash and Cash Equivalents at End of Year	**$ 74,606**	$ 68,744	$ 28,592
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $(113), $9,178 and $19,092 capitalized, respectively)	**$ 85,168**	$ 60,396	$ 50,248

Income taxes (net of refunds and investment tax credits)	**(219,641)**	(226,179)	(175,269)
Noncash transactions —			
Accrued property additions at year-end	**852**	5,567	11,203
Acquisitions	**228,964**	—	—
Capital contributions from noncontrolling interests	**220,734**	—	—

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Power Company and Subsidiary Companies 2014 Annual Report

Assets	**2014**	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 74,606**	$ 68,744
Receivables —		
Customer accounts receivable	**76,608**	73,497
Other accounts receivable	**14,707**	3,983
Affiliated companies	**34,223**	38,391
Fossil fuel stock, at average cost	**21,755**	19,178
Materials and supplies, at average cost	**57,843**	54,780
Prepaid income taxes	**19,239**	54,523
Deferred income taxes, current	**305,814**	209
Other prepaid expenses	**17,301**	20,946
Assets from risk management activities	**5,297**	182
Total current assets	**627,393**	334,433
Property, Plant, and Equipment:		
In service	**5,656,974**	4,696,134
Less accumulated provision for depreciation	**1,034,610**	871,963
Plant in service, net of depreciation	**4,622,364**	3,824,171
Construction work in progress	**10,511**	9,843
Total property, plant, and equipment	**4,632,875**	3,834,014
Other Property and Investments:		
Goodwill	**1,839**	1,839
Other intangible assets, net of amortization of $8,279 and $5,614 at December 31, 2014 and December 31, 2013, respectively	**47,091**	43,505
Total other property and investments	**48,930**	45,344
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**123,573**	141,851
Other deferred charges and assets — affiliated	**5,492**	4,605
Other deferred charges and assets — non-affiliated	**111,239**	68,853
Total deferred charges and other assets	**240,304**	215,309
Total Assets	**$ 5,549,502**	$ 4,429,100

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
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Liabilities and Stockholders' Equity	2014	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 525,295	$ 599
Notes Payable	194,917	—
Accounts payable —		
Affiliated	78,279	56,661
Other	30,037	20,747
Accrued taxes —		
Accrued income taxes	71,700	161
Other accrued taxes	2,983	2,662
Accrued interest	29,518	28,352
Other current liabilities	14,761	18,492
Total current liabilities	947,490	127,674
Long-Term Debt:		
Senior notes —		
4.875% due 2015	—	525,000
6.375% due 2036	200,000	200,000
5.15% due 2041	575,000	575,000
5.25% due 2043	300,000	300,000
Other long-term notes (3.25% due 2032-2034)	18,775	17,787
Unamortized debt premium	2,378	2,467
Unamortized debt discount	(813)	(1,013)
Long-term debt	1,095,340	1,619,241
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	862,795	724,390
Investment tax credits	600,519	340,269
Deferred capacity revenues — affiliated	15,279	15,279
Other deferred credits and liabilities — affiliated	604	1,621
Other deferred credits and liabilities — non-affiliated	16,890	7,896
Total deferred credits and other liabilities	1,496,087	1,089,455
Total Liabilities	3,538,917	2,836,370
Redeemable Noncontrolling Interest	39,241	28,778
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	—	—
Paid-in capital	1,175,392	1,029,035
Retained earnings	573,178	531,998
Accumulated other comprehensive income	3,286	2,919
Total common stockholder's equity	1,751,856	1,563,952
Noncontrolling Interest	219,488	—
Total Stockholders' Equity	1,971,344	1,563,952
Total Liabilities and Stockholders' Equity	$ 5,549,502	$ 4,429,100
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2014 , 2013 , and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity	Noncontrolling Interest	Total
					(in thousands)			
Balance at December 31, 2011	1	$ —	$1,028,210	$447,301	$ (6,829)	$ 1,468,682	$ —	$ 1,468,682
Net income attributable to Southern Power Company	—	—	—	175,285	—	175,285	—	175,285
Capital contributions from parent company	—	—	(662)	—	—	(662)	—	(662)
Other comprehensive income	—	—	—	—	6,053	6,053	—	6,053
Cash dividends on common stock	—	—	—	(127,000)	—	(127,000)	—	(127,000)
Other	—	—	—	(1)	—	(1)	—	(1)
Balance at December 31, 2012	1	—	1,027,548	495,585	(776)	1,522,357	—	1,522,357
Net income attributable to Southern Power Company	—	—	—	165,533	—	165,533	—	165,533
Capital contributions from parent company	—	—	1,487	—	—	1,487	—	1,487
Other comprehensive income	—	—	—	—	3,695	3,695	—	3,695
Cash dividends on common stock	—	—	—	(129,120)	—	(129,120)	—	(129,120)
Balance at December 31, 2013	**1**	**—**	**1,029,035**	**531,998**	**2,919**	**1,563,952**	**—**	**1,563,952**
Net income attributable to Southern Power Company	**—**	**—**	**—**	**172,300**	**—**	**172,300**	**—**	**172,300**
Capital contributions from parent company	**—**	**—**	**146,357**	**—**	**—**	**146,357**	**—**	**146,357**
Other comprehensive income	**—**	**—**	**—**	**—**	**367**	**367**	**—**	**367**
Cash dividends on common stock	**—**	**—**	**—**	**(131,120)**	**—**	**(131,120)**	**—**	**(131,120)**
Capital contributions from noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**220,734**	**220,734**
Net loss attributable to noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**(1,246)**	**(1,246)**
Balance at December 31, 2014	**1**	**$ —**	**$1,175,392**	**$573,178**	**$ 3,286**	**$ 1,751,856**	**$ 219,488**	**$ 1,971,344**

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO FINANCIAL STATEMENTS
Southern Power Company and Subsidiary Companies 2014 Annual Report

Index to the Notes to Financial Statements

NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company is a wholly-owned subsidiary of The Southern Company (Southern Company), which is also the parent company of four traditional operating companies, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

Southern Power Company and certain of its generation subsidiaries are subject to regulation by the FERC. The Company follows GAAP. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. This includes an adjustment to the presentation of prepaid long-term service agreements (LTSA) to present amounts as noncurrent assets on the consolidated balance sheets. Prior period amounts recorded within other current assets have been reclassified to conform to the current presentation. See "Long-Term Service Agreements" herein for additional information.

The financial statements include the accounts of Southern Power Company and its wholly-owned subsidiaries, Southern Company – Florida, LLC, Oleander Power Project, LP, and Nacogdoches Power, LLC, which own, operate, and maintain the Company's ownership interests in Plants Stanton Unit A, Oleander, and Nacogdoches, respectively. The financial statements also include the accounts of Southern Power Company's wholly-owned subsidiaries, SRE and SRP. SRE and SRP were formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. Through STR, a jointly-owned subsidiary owned 90% by SRE and 10% by TRE, SRE and its subsidiaries own, operate, and maintain Plants Adobe, Apex, Campo Verde, Cimarron, Granville, Macho Springs, and Spectrum. Through SG2 Holdings, a jointly-owned subsidiary owned 51% by SRP and 49% by First Solar, SRP owns, operates, and maintains Plant Imperial Valley. All intercompany accounts and transactions have been eliminated in consolidation.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

Affiliate Transactions

Southern Power Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations, construction management, and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for all of these services from SCS amounted to approximately $125.9 million in 2014 , $117.6 million in 2013 , and $125.4 million in 2012 . Of these costs, approximately $124.8 million in 2014 , $114.3 million in 2013 , and $107.7 million in 2012 were other operations and maintenance expenses; the remainder was recorded to plant in service. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has several agreements with SCS for transmission services. Transmission purchased from affiliates totaled $6.8 million in 2014 , $8.3 million in 2013 , and $6.6 million in 2012 . All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

Total billings for all PPAs with affiliates were $156.4 million , $148.4 million , and $159.9 million in 2014 , 2013 , and 2012 , respectively. Deferred amounts outstanding as of December 31 are included in the balance sheet as follows:

		2014		2013
		(in millions)		
Other deferred charges and assets - affiliated	**$**	**2.9**	$	1.9
Other current liabilities		**—**		(4.2)
Deferred capacity revenues - affiliated		**(15.3)**		(15.3)
Total deferred amounts outstanding	**$**	**(12.4)**	$	(17.6)

Revenue recognized under affiliate PPAs accounted for as operating leases totaled $74.8 million , $69.0 million , and $76.2 million in 2014 , 2013 , and 2012 , respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See "Revenues" herein for additional information.

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations. Accordingly, the Company includes these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 for further information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed. Transmission revenues and other fees are recognized as earned as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for the top three customers:

	2014	2013	2012
FPL	**10.1%**	11.8%	12.8%
Georgia Power	**9.7%**	10.7%	12.5%
Duke Energy Corporation	**9.1%**	10.3%	5.9%

NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

Under the American Recovery and Reinvestment Act of 2009 (ARRA), and the American Taxpayer Relief Act of 2012 (ATRA), certain projects are eligible for federal ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $11.4 million , $5.5 million , and $2.6 million in 2014 , 2013 , and 2012, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. Federal and state ITCs available to reduce income taxes payable were not fully utilized during the year and will be carried forward and utilized in future years. See Note 5 under "Effective Tax Rate" for additional information.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

The Company's depreciable property, plant, and equipment consists entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred.

Depreciation

Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets as determined by management. Certain generation assets are now depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 35 to 45 years . The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term. The book value of plant-in-service as of December 31, 2014 that is depreciated on a units-of-production basis was approximately $470.2 million .

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation of the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives as determined by management.

Long-Term Service Agreements

The Company has entered into LTSAs for the purpose of securing maintenance support for substantially all of its generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in noncurrent assets on the balance sheets and are recorded as payments pursuant to LTSAs in the statements of cash flows. All work performed is capitalized or charged to expense as appropriate based on the nature of the work when performed; therefore, these charges are non-cash and are not reflected in the statements of cash flows.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years . The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

The amortization expense for the acquired PPAs for the years ended December 31, 2014, 2013, and 2012 was $2.5 million , $2.5 million , and $1.7 million , respectively, and the amortization for future periods is as follows:

	Amortization Expense
	(in millions)
2015	$ 2.5
2016	2.4
2017	2.5
2018	2.5
2019	2.5
2020 and beyond	28.5
Total	$ 40.9

Emission Reduction Credits

The Company has acquired emission reduction credits necessary for future unspecified construction in areas designated by the EPA as non-attainment areas for nitrogen oxide or volatile organic compound emissions. These credits are reflected on the balance sheets at historical cost. The cost of emission reduction offsets to be surrendered are generally transferred to CWIP upon commencement of construction. The total emission reduction credits were $11.0 million at December 31, 2014 and 2013 .

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several generating units. The Company has contracts in place for natural gas storage to support normal operations of the Company's natural gas generating units. The Company maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 8 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions result in the deferral of related gains and losses in AOCI until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. See Note 9 for additional information regarding derivatives. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014 .

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications of amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS

2014

Adobe Solar, LLC

On April 17, 2014, the Company and TRE, through STR, a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Adobe from Sun Edison, LLC, the original developer of the project. Adobe constructed and owns an approximately 20 -MW solar generating facility in Kern County, California. The solar facility began commercial operation on May 21, 2014 and the entire output of the plant is contracted under a 20 -year PPA with SCE. The acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Adobe included cash consideration of approximately $96.2 million , which included TRE's 10% equity contribution. The fair values of the assets, liabilities, and intangibles acquired were recorded as follows: $83.5 million to property, plant, and equipment, $14.5 million to prepayment related to transmission services, and $6.3 million to PPA intangible, resulting in a $5.2 million bargain purchase gain with a $2.9 million deferred tax liability. The bargain purchase gain is included in other income (expense), net in the Company's Statements of Income herein. Acquisition-related costs were expensed as incurred and were not material.

Macho Springs Solar, LLC

On May 22, 2014, the Company and TRE, through STR, acquired all of the outstanding membership interests of Macho Springs from First Solar Development, LLC, the original developer of the project. Macho Springs constructed and owns an approximately 50 -MW solar photovoltaic facility in Luna County, New Mexico. The solar facility began commercial operation on May 23, 2014 and the entire output of the plant is contracted under a 20 -year PPA with EPE . The acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Macho Springs included cash consideration of approximately $130.0 million , which included TRE's 10% equity contribution. The fair values of the assets acquired were recorded as follows: $128.0 million to property, plant, and equipment, $1.0 million to prepaid property taxes, and $1.0 million to prepayment related to transmission services. The acquisition did not include any contingent consideration. Acquisition-related costs were expensed as incurred and were not material.

NOTES (continued)
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SG2 Imperial Valley, LLC

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150 -MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and at that time a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The entire output of the plant is contracted under a 25 -year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy (SDG&E). The acquisition was in accordance with the Company's overall growth strategy.

In connection with this acquisition, SG2 Holdings made an aggregate payment of approximately $127.9 million to a subsidiary of First Solar and became obligated to pay additional contingent consideration of approximately $599.3 million upon completion of the facility (representing the amount due to an affiliate of First Solar under the construction contract for Imperial Valley). When substantial completion was achieved on November 26, 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The members of SG2 Holdings made additional agreed upon capital contributions totaling $593.3 million to SG2 Holdings that were used to pay the contingent consideration due, leaving $6.0 million of contingent consideration payable upon final acceptance of the facility. As a result of these capital contributions, the aggregate purchase price payable by the Company for the acquisition of Imperial Valley was approximately $504.7 million in addition to the $222.5 million noncash contribution by the minority member. Following these capital contributions, the Company indirectly owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to this transaction. As of December 31, 2014, the fair values of the assets acquired were recorded as follows: $707.5 million to property, plant, and equipment and $19.7 million to prepayment related to transmission services; however, the allocation of the purchase price to individual assets has not been finalized. Acquisition-related costs were expensed as incurred and were not material.

2013

Campo Verde Solar, LLC

In April 2013, the Company and TRE, through STR, acquired all of the outstanding membership interests of Campo Verde from First Solar, the developer of the project. Campo Verde constructed and owns an approximately 139 -MW solar photovoltaic facility in Southern California. The solar facility began commercial operation in October 2013 and the entire output of the plant is contracted under a 20 -year PPA with SDG&E. The asset acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Campo Verde included cash consideration of $136.6 million , which included TRE's 10% equity contribution. The fair value of the assets acquired was allocated entirely to property, plant, and equipment. The acquisition did not include any contingent consideration and due diligence costs were expensed as incurred and were not material. Under an engineering, procurement, and construction agreement, an additional $355.5 million was paid to a subsidiary of First Solar for construction of the solar facility.

Subsequent Events

Decatur County Solar Projects

On February 19, 2015, the Company acquired all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. as part of the Company's plans to build two solar photovoltaic facilities; the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80 -MW and 19 -MW, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015 , and the entire output of each project is contracted to Georgia Power. The entire output of the Decatur Parkway Solar Project is contracted under a 25 -year PPA with Georgia Power and the entire output of the Decatur County Solar Project is contracted under a separate 20 -year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million , which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. The acquisition is in accordance with the Company's overall growth strategy.

Kay County Wind Facility

On February 24, 2015, the Company, through its wholly-owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind. Kay Wind is constructing an approximately 299 -MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015 . The entire output of the facility is contracted under separate 20 -year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Kay Wind is expected to close in the fourth quarter 2015 and the purchase price is expected to be approximately $492 million , with potential purchase price adjustments based on performance testing. The completion of the acquisition is subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing. The ultimate outcome of this matter cannot be determined at this time.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2014 , $156.5 million was recorded in plant in service with associated accumulated depreciation of $46.6 million . These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files separate company income tax returns for the States of Florida, New Mexico, South Carolina, and Tennessee. Unitary income tax returns are filed for the States of California, North Carolina, and Texas. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in millions)	
Federal —			
Current	$ 178.6	$ (120.2)	$ (133.1)
Deferred	(166.0)	158.7	210.4
	12.6	38.5	77.3
State —			
Current	(13.8)	(5.2)	(3.0)
Deferred	(2.0)	12.6	18.3
	(15.8)	7.4	15.3
Total	$ (3.2)	$ 45.9	$ 92.6

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	$ 1,006.5	$ 829.5
Basis difference on asset transfers	2.6	2.8
Levelized capacity revenues	17.1	11.2
Other	5.7	0.9
Total	1,031.9	844.4
Deferred tax assets —		
Federal effect of state deferred taxes	28.9	29.7
Net basis difference on federal ITCs	101.5	58.0
Alternative minimum tax carryforward	15.0	1.1
Unrealized tax credits	305.2	—
Unrealized loss on interest rate swaps	6.1	11.2
Levelized capacity revenues	4.9	6.0
Deferred state tax assets	14.5	17.0
Other	4.1	4.7
Total	480.2	127.7
Valuation Allowance	(7.5)	(7.5)
Net deferred income tax assets	472.7	120.2
Total deferred tax liabilities, net	559.2	724.2
Portion included in current assets/(liabilities), net	303.6	0.2
Accumulated deferred income taxes	$ 862.8	$ 724.4

Deferred tax liabilities are the result of property related timing differences.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

Deferred tax assets consist primarily of timing differences related to net basis differences on federal ITCs and the carryforward of unrealized federal ITCs.

At December 31, 2014 and December 31, 2013 , the Company had state net operating loss (NOL) carryforwards of $246.6 million and $240.8 million , respectively. The NOL carryforwards resulted in deferred tax assets of $9.4 million as of December 31, 2014 and $11.0 million as of December 31, 2013 . The Company has established a valuation allowance due to the remote likelihood that the full tax benefits will be realized. During 2014 , the estimated amount of NOL utilization decreased resulting in a $15.1 million increase in the valuation allowance. The increase in income tax expense resulting from the higher valuation allowance was offset by the net income impact of a decrease in the deferred tax balance due to a reduction in the state's statutory tax rate.

Of the NOL balance at December 31, 2014 , approximately $87.0 million will expire in 2015 and $40.0 million will expire in 2017.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2014	2013	2012
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
State income tax, net of federal deduction	**(6.0)**	2.2	3.7
Amortization of ITC	**(4.3)**	(1.7)	(1.0)
ITC basis difference	**(27.7)**	(14.5)	(2.6)
Other	**1.1**	0.3	(0.6)
Effective income tax rate	**(1.9)%**	21.3 %	34.5 %

The Company's effective tax rate decreased in 2014 primarily due to increased benefits from federal ITCs related to Plants Adobe, Macho Springs, and Imperial Valley. The Company's effective tax rate decreased in 2013 primarily due to tax benefits from federal ITCs related to Plants Campo Verde and Spectrum.

In 2009, President Obama signed into law the ARRA. Major tax incentives in the ARRA included renewable energy incentives. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014.

The Company received cash related to federal ITCs under the renewable energy initiatives of $73.5 million in tax year 2014, $158.1 million in tax year 2013, and $45.0 million in tax year 2012. The tax benefit of the related basis difference reduced income tax expense by $47.5 million in 2014 , $31.3 million in 2013, and $7.8 million in 2012.

See Note 1 under "Income and Other Taxes" for additional information.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 1.5**	$ 2.9	$ 2.6
Tax positions increase from current periods	**4.7**	1.6	0.7
Tax positions decrease from prior periods	**(1.5)**	(3.0)	(0.2)
Reductions due to settlements	**—**	—	(0.2)
Balance at end of year	**$ 4.7**	$ 1.5	$ 2.9

The increase in tax positions from current periods for 2014 and 2013 and the decrease from prior periods in 2014 relates to federal ITCs. The decrease in tax positions from prior periods for 2013 relates to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in millions)	
Tax positions impacting the effective tax rate	**$4.7**	$1.5	$0.3
Tax positions not impacting the effective tax rate	**—**	—	2.6
Balance of unrecognized tax benefits	**$4.7**	$1.5	$2.9

The tax positions impacting the effective tax rate for 2014 and 2013 relate to federal ITCs. The tax positions not impacting the effective tax rate for 2012 related to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months . The settlement of federal and state audits could impact the balances. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2010.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had $525.0 million of senior notes due within one year. In addition, at December 31, 2014, the Company classified as due within one year approximately $0.3 million of long-term debt payable to TRE that is expected to be repaid in 2015. At December 31, 2013, the Company classified approximately $0.6 million of long-term debt payable to TRE as due within one year.

There are no additional scheduled maturities of long-term debt through 2019.

Other Long-Term Notes

During 2014 , the Company prepaid $9.5 million of long-term debt payable to TRE and issued $0.1 million due June 15, 2032, $0.8 million due April 30, 2033, $3.9 million due April 30, 2034, and $5.4 million due May 31, 2034 under promissory notes payable to TRE related to the financing of Apex, Campo Verde, Adobe, and Macho Springs, respectively. At December 31, 2014, and 2013, the Company had $18.8 million and $17.8 million , respectively, of long-term debt payable to TRE.

Senior Notes

During 2013, Southern Power Company issued $300 million aggregate principal amount of its Series 2013A 5.25% Senior Notes due July 15, 2043. The net proceeds from the sale of the Series 2013A Senior Notes were used to repay a portion of its outstanding short-term indebtedness and for other general corporate purposes, including the Company’s continuous construction program.

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At December 31, 2014 and 2013 , Southern Power Company had $1.6 billion of senior notes outstanding, which included senior notes due within one year.

Bank Credit Arrangements

In February 2013, Southern Power Company amended its $500 million committed credit facility (Facility), which extended the maturity date from 2016 to 2018. As of December 31, 2014 , the total amount available under the Facility was $488 million . There were no borrowings outstanding under the Facility at December 31, 2013 . The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, Southern Power Company plans to renew the Facility prior to its expiration.

Southern Power Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% . At December 31, 2014 , the Company was in compliance with its debt limits.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings are shown below. The Company had no short-term borrowings in 2013.

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014	$ 195	0.4%

Dividend Restrictions

Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

The indenture related to certain series of Southern Power Company's senior notes also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60% . At December 31, 2014 , Southern Power Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities which are not recognized on the Company's balance sheets. In 2014 , 2013 , and 2012 , the Company incurred fuel expense of $596.3 million , $473.8 million , and $426.3 million , respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional operating companies. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $4.0 million , $1.9 million , and $0.8 million for 2014 , 2013 , and 2012 , respectively. These amounts include contingent rent expense related to the Plant Stanton Unit A land lease based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. As of December 31, 2014 , estimated minimum lease payments under operating leases were $4.5 million in 2015 , $4.5 million in 2016 , $4.6 million in 2017 , $4.6 million in 2018 , $4.7 million in 2019 , and $157.2 million in 2020 and thereafter. The majority of the committed future expenditures are land leases at solar facilities.

Redeemable Noncontrolling Interest

Pursuant to an agreement with TRE, on or after November 25, 2015, or earlier in the event of the death of the controlling member of TRE, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

See Note 10 for additional information.

8. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2014 , assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in millions)		
Assets:				
Energy-related derivatives	$ —	$ 5.5	$ —	$ 5.5
Cash equivalents	18.0	—	—	18.0
Total	$ 18.0	$ 5.5	$ —	$ 23.5
Liabilities:				
Energy-related derivatives	$ —	$ 3.6	$ —	$ 3.6

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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	$ —	$ 0.6	$ —	$ 0.6
Cash equivalents	68.0	—	—	68.0
Total	$ 68.0	$ 0.6	$ —	$ 68.6
Liabilities:				
Energy-related derivatives	$ —	$ 0.6	$ —	$ 0.6

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. See Note 9 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013 , the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2014:	*(in millions)*			
Cash equivalents:				
Money market funds	$ 18.0	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$ 68.0	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013 , other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2014	**$ 1,621**	**$ 1,785**
2013	$ 1,620	$ 1,660

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

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9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 8 herein for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014 , the net volume of energy-related derivative contracts for natural gas positions totaled 3.4 million mmBtu, all of which expire by 2017 , which is the longest non-hedge date. At December 31, 2014 , the net volume of energy-related derivative contracts for power positions was immaterial. In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 1.0 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives from time to time to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges, where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2014 , there were no interest rate derivatives outstanding.

The estimated pre-tax loss that will be reclassified from AOCI to interest expense for the 12-month period ending December 31, 2015 is $1.0 million . The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

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Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013 , the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in millions)			*(in millions)*	
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	**$ 5.3**	$ 0.2	Other current liabilities	**$ 3.5**	$ 0.6
	Other deferred charges and assets – non-affiliated	**0.2**	0.4	Other deferred credits and liabilities – non-affiliated	**0.1**	—
Total derivatives not designated as hedging instruments		**$ 5.5**	$ 0.6		**$ 3.6**	$ 0.6

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure tables below.

	Fair Value				
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 5.5**	$ 0.6	Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 3.6**	$ 0.6
Gross amounts not offset in the Balance Sheet [(b)]	**(0.1)**	(0.1)	Gross amounts not offset in the Balance Sheet [(b)]	**(0.1)**	(0.1)
Net energy-related derivative assets	**$ 5.4**	$ 0.5	**Net energy-related derivative liabilities**	**$ 3.5**	$ 0.5

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

For the years ended December 31, 2014 , 2013 , and 2012 , the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Reclassified from AOCI into Income (Effective Portion)**			
			Amount	
Derivative Category	**Statements of Income Location**	**2014**	2013	2012
			(in millions)	
Energy-related derivatives	Depreciation and amortization	**$ 0.4**	$ 0.4	$ 0.4
Interest rate derivatives	Interest expense, net of amounts capitalized	**(0.9)**	(6.5)	(10.5)
Total		**$ (0.5)**	$ (6.1)	$ (10.1)

There was no material ineffectiveness recorded in earnings for any period presented.

For the Company's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. The pre-tax effects of energy-related derivatives not

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designated as hedging instruments on the Company's statements of income were immaterial for the years ended December 31, 2014 , 2013 , and 2012 . This third party hedging activity has been discontinued.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014 , the amount of collateral posted with its derivative counterparties was immaterial.

At December 31, 2014 , the fair value of derivative liabilities with contingent features was $1.5 million . However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million , and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

10. NONCONTROLLING INTEREST

The following table details the components of redeemable noncontrolling interests for the years ended December 31:

	2014	2013	2012
		(in millions)	
Beginning balance	**$ 28.8**	$ 8.1	$ 3.8
Net income attributable to redeemable noncontrolling interest	**4.0**	3.9	0.9
Distributions to redeemable noncontrolling interest	**(1.1)**	(0.5)	—
Capital contributions from redeemable noncontrolling interest	**7.5**	17.3	3.4
Ending balance	**$ 39.2**	$ 28.8	$ 8.1

For the year ended December 31, 2014, net income included in the consolidated statements of changes in stockholders' equity is reconciled to net income presented in the consolidated statements of income as follows:

	2014
Net income attributable to Southern Power Company	**$ 172.3**
Net loss attributable to noncontrolling interest	**(1.2)**
Net income attributable to redeemable noncontrolling interest	**4.0**
Net income	**$ 175.1**

For the years ended December 31, 2013 and 2012, net income attributable to redeemable noncontrolling interest was $3.9 million and $0.9 million , respectively, and was included in "Other income (expense), net" in the consolidated statements of income.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income Attributable to Southern Power Company
		(in thousands)	
March 2014	**$ 350,854**	**$ 59,358**	**$ 33,471**
June 2014	**328,803**	**51,073**	**30,812**
September 2014	**435,256**	**104,710**	**63,631**
December 2014	**386,336**	**40,138**	**44,386**
March 2013	$ 302,947	$ 64,673	$ 29,192
June 2013	307,255	55,024	27,922
September 2013	364,767	116,497	85,153
December 2013	300,257	53,781	23,266

The Company's business is influenced by seasonal weather conditions.

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	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Wholesale — non-affiliates	**$ 1,115,880**	$ 922,811	$ 753,653	$ 870,607	$ 752,772
Wholesale — affiliates	**382,523**	345,799	425,180	358,585	370,630
Total revenues from sales of electricity	**1,498,403**	1,268,610	1,178,833	1,229,192	1,123,402
Other revenues	**2,846**	6,616	7,215	6,769	6,939
Total	**$ 1,501,249**	$ 1,275,226	$ 1,186,048	$ 1,235,961	$ 1,130,341
Net Income Attributable to Southern Power Company (in thousands)	**$ 172,300**	$ 165,533	$ 175,285	$ 162,231	$ 131,309
Cash Dividends on Common Stock (in thousands)	**$ 131,120**	$ 129,120	$ 127,000	$ 91,200	$ 107,100
Return on Average Common Equity (percent)	**10.39**	10.73	11.72	11.88	10.68
Total Assets (in thousands)	**$ 5,549,502**	$ 4,429,100	$ 3,779,927	$ 3,580,977	$ 3,437,734
Gross Property Additions and Acquisitions (in thousands)	**$ 942,454**	$ 632,919	$ 240,692	$ 254,725	$ 404,644
Capitalization (in thousands):					
Common stock equity	**$ 1,751,856**	$ 1,563,952	$ 1,522,357	$ 1,468,682	$ 1,263,220
Redeemable noncontrolling interest	**39,241**	28,778	8,069	3,825	—
Noncontrolling interest	**219,488**	—	—	—	—
Long-term debt	**1,095,340**	1,619,241	1,306,099	1,302,758	1,302,619
Total (excluding amounts due within one year)	**$ 3,105,925**	$ 3,211,971	$ 2,836,525	$ 2,775,265	$ 2,565,839
Capitalization Ratios (percent):					
Common stock equity	**56.4**	48.7	53.7	52.9	49.2
Redeemable noncontrolling interest	**1.3**	0.9	0.3	0.1	—
Noncontrolling interest	**7.1**	—	—	—	—
Long-term debt	**35.2**	50.4	46.0	47.0	50.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands):					
Wholesale — non-affiliates	**19,014,445**	15,110,616	15,636,986	16,089,875	13,294,455
Wholesale — affiliates	**11,193,530**	9,359,500	16,373,245	11,773,890	10,494,339
Total	**30,207,975**	24,470,116	32,010,231	27,863,765	23,788,794
Average Revenue Per Kilowatt-Hour (cents)	**4.96**	5.18	3.68	4.41	4.72
Plant Nameplate Capacity Ratings (year-end) (megawatts)*	**9,185**	8,924	8,764	7,908	7,908
Maximum Peak-Hour Demand (megawatts):					
Winter	**3,999**	2,685	3,018	3,255	3,295
Summer	**3,998**	3,271	3,641	3,589	3,543
Annual Load Factor (percent)	**51.8**	54.2	48.6	51.0	54.0
Plant Availability (percent)**	**91.8**	91.8	92.9	93.9	94.0
Source of Energy Supply (percent):					
Gas	**86.0**	88.5	91.0	89.2	88.8
Alternative (Solar and Biomass)	**2.9**	1.1	0.5	0.2	—
Purchased power —					
From non-affiliates	**6.4**	6.4	7.2	6.7	5.5
From affiliates	**4.7**	4.0	1.3	3.9	5.7
Total	**100.0**	100.0	100.0	100.0	100.0

* Plant nameplate capacity ratings include 100% of all solar facilities. When taking into consideration the Company's 90% equity interest in STR (which includes Plants Adobe, Apex, Campo Verde, Cimarron, Macho Springs and Spectrum) and 51% equity interest in SG2 Holdings (which includes Plant Imperial Valley), the Company's equity portion of total nameplate capacity for 2014 is 9,074 MW.

** Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

PART III

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10 and in paragraph (b) in Item 12), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2015 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Equity Plan Compensation Information" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10 and in paragraph (b) in Item 12), 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2015 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12, and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power **(1)**

S. W. Connally, Jr. President and Chief Executive Officer Age 45 Served as Director since 2012	**Julian B. MacQueen (2)** Age 64 Served as Director since 2013
Allan G. Bense (2) Age 63 Served as Director since 2010	**J. Mort O'Sullivan, III (2)** Age 63 Served as Director since 2010
Deborah H. Calder (2) Age 54 Served as Director since 2010	**Michael T. Rehwinkel (2)** Age 58 Served as Director since 2013
William C. Cramer, Jr. (2) Age 62 Served as Director since 2002	**Winston E. Scott (2)** Age 64 Served as Director since 2003

(1) *Ages listed are as of December 31, 2014.*

(2) *No position other than director.*

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 24, 2014) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power (1)

S. W. Connally, Jr. President and Chief Executive Officer Age 45 Served as Executive Officer since 2012	**Michael L. Burroughs** Vice President — Senior Production Officer Age 54 Served as Executive Officer since 2010
Jim R. Fletcher Vice President — External Affairs and Corporate Services Age 48 Served as Executive Officer since 2014	**Wendell E. Smith** Vice President — Power Delivery Age 49 Served as Executive Officer since 2014
Richard S. Teel Vice President and Chief Financial Officer Age 44 Served as Executive Officer since 2010	**Bentina C. Terry** Vice President — Customer Service and Sales Age 44 Served as Executive Officer since 2007

(1) *Ages listed are as of December 31, 2014.*

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

DIRECTORS

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

S. W. Connally, Jr. - President and Chief Executive Officer of Gulf Power since July 2012. Mr. Connally has also served as Chairman of Gulf Power's Board of Directors since July 2012. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from July 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming. Mr. Bense served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011. Mr. Bense is also a member of the board of directors of Capital City Bank Group, Inc.

Deborah H. Calder - Executive Vice President for Navy Federal Credit Union since 2014. From 2008 to 2014, she served as Senior Vice President. Ms. Calder directs the day-to-day operations of more than 4,000 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 23 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida, Georgia, and Alabama. Mr. Cramer has been an authorized Chevrolet dealer for over 25 years. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

Julian B. MacQueen - Founder and Chief Executive Officer of Innisfree Hotels, Inc. He is currently a member of the American Hotel & Lodging Association and a director of the Beach Community Bank.

J. Mort O'Sullivan, III - Managing Member of the Warren Averett O'Sullivan Creel division of Warren Averett, LLC, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor.

Michael T. Rehwinkel - Executive Chairman of EVRAZ North America, a steel manufacturer, since July 2013. He previously served as Chief Executive Officer and President of EVRAZ North America from February 2010 to July 2013 and previously held various executive positions at Georgia-Pacific Corporation. Mr. Rehwinkel is also Chairman of the American Iron and Steel Institute. Mr. Rehwinkel has more than 30 years of industrial business and leadership experience.

Winston E. Scott - Senior Vice President for External Relations and Economic Development, Florida Institute of Technology since March 2012. He previously served as Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida from August 2008 through March 2012. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation. Mr. Scott's experience includes serving as a pilot in the U.S. Navy, an astronaut with the National Aeronautic and Space Administration, Executive Director of the Florida Space Authority, and Vice President of Jacobs Engineering.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010.

Jim R. Fletcher - Vice President of External Affairs and Corporate Services since March 2014. He previously served as Vice President of Governmental and Regulatory Affairs for Georgia Power from January 2011 to February 2014 and Regulatory Affairs Manager for Georgia Power from March 2006 to January 2011.

Wendell E. Smith - Vice President of Power Delivery since March 2014. He previously served as the General Manager of Distribution Engineering, Construction and Maintenance and Distribution Operations Systems for Georgia Power from January 2012 to February 2014, Transmission Construction Manager for Georgia Power from February 2011 to December 2011, and Distribution Manager for Georgia Power from March 2005 to February 2011.

Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010.

Bentina C. Terry - Vice President of Customer Service and Sales since March 2014. She previously served as Vice President of External Affairs and Corporate Services from March 2007 to March 2014.

Involvement in certain legal proceedings. None.

Promoters and Certain Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com . The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com . The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Southern Company owns all of Gulf Power’s outstanding common stock and Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. In addition, under the rules of the SEC, Gulf Power is exempt from the audit committee requirements of Section 301 of the Sarbanes-Oxley Act of 2002 and, therefore, is not required to have an audit committee or an audit committee report on whether it has an audit committee financial expert.

Item 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2014, as well as each of its other three most highly compensated executive officers serving at the end of the year.

S. W. Connally, Jr.	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
Jim R. Fletcher	Vice President
Bentina C. Terry	Vice President

Also described is the compensation of Gulf Power's former Vice President, P. Bernard Jacob, who retired from Gulf Power effective as of May 3, 2014. Collectively, these officers are referred to as the named executive officers.

Executive Summary

Performance and Pay

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2014.

	Salary ($) (1)	% of Total	Short-Term Performance Pay ($) (1)	% of Total	Long-Term Performance Pay ($) (1)	% of Total
S. W. Connally, Jr.	393,907	31%	339,302	27%	517,692	42%
R. S. Teel	252,110	45%	161,989	29%	152,101	26%
M. L. Burroughs	199,209	50%	121,801	30%	80,103	20%
J. R. Fletcher	224,547	49%	149,633	33%	84,480	18%
B. C. Terry	270,543	45%	173,833	29%	163,191	26%

(1) Salary is the actual amount paid in 2014, Short-Term Performance Pay is the actual amount earned in 2014 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2014. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A. Information is provided for named executive officers serving at the end of 2014.

Gulf Power financial and operational and Southern Company earnings per share (EPS) goal results for 2014, as adjusted and further described in this CD&A, are shown below:

Financial: 100% of Target Operational: 149% of Target EPS: 176% of Target

Southern Company's annualized total shareholder return has been:

1-Year: 25.23% 3-Year: 6.67% 5-year: 13.22%

These levels of achievement resulted in payouts that were aligned with Gulf Power and Southern Company performance.

Compensation and Benefit Beliefs and Practices

The compensation and benefit program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power's executive compensation program should:

- Be competitive with Gulf Power's industry peers;
- Motivate and reward achievement of Gulf Power's goals;
- Be aligned with the interests of Southern Company's stockholders and Gulf Power's customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power's and Southern Company's business goals. Gulf Power believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for Southern Company's stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by Southern Company's EPS performance. Long-term performance pay is tied to Southern Company's stockholder value, with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance shares, which reward Southern Company's total shareholder return performance relative to that of industry peers and stock price appreciation .

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention by the Compensation Committee of an independent compensation consultant, Pay Governance, that provides no other services to Gulf Power or Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited ongoing perquisites with no income tax gross-ups for the President and Chief Executive Officer except on certain relocation-related benefits.
- "No-hedging" provision in Gulf Power's insider trading policy that is applicable to all employees.
- Strong stock ownership requirements that are being met by all named executive officers.

ESTABLISHING EXECUTIVE COMPENSATION

The Compensation Committee establishes the Southern Company system executive compensation program. In doing so, the Compensation Committee uses information from others, principally Pay Governance. The Compensation Committee also relies on information from Southern Company's Human Resources staff and, for individual executive officer performance, from Southern Company's and Gulf Power's respective Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Southern Company Stockholder Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on Southern Company's executive compensation at the Southern Company 2014 annual meeting of stockholders. In light of the significant support of Southern Company's stockholders (94% of votes cast voting in favor of the proposal) and the actual payout levels of the performance-based compensation program, the Compensation Committee continues to believe that the executive compensation program is competitive, aligned with Gulf Power's and Southern Company's financial and operational performance, and in the best interests of Gulf Power's customers and Southern Company's stockholders.

Executive Compensation Focus

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

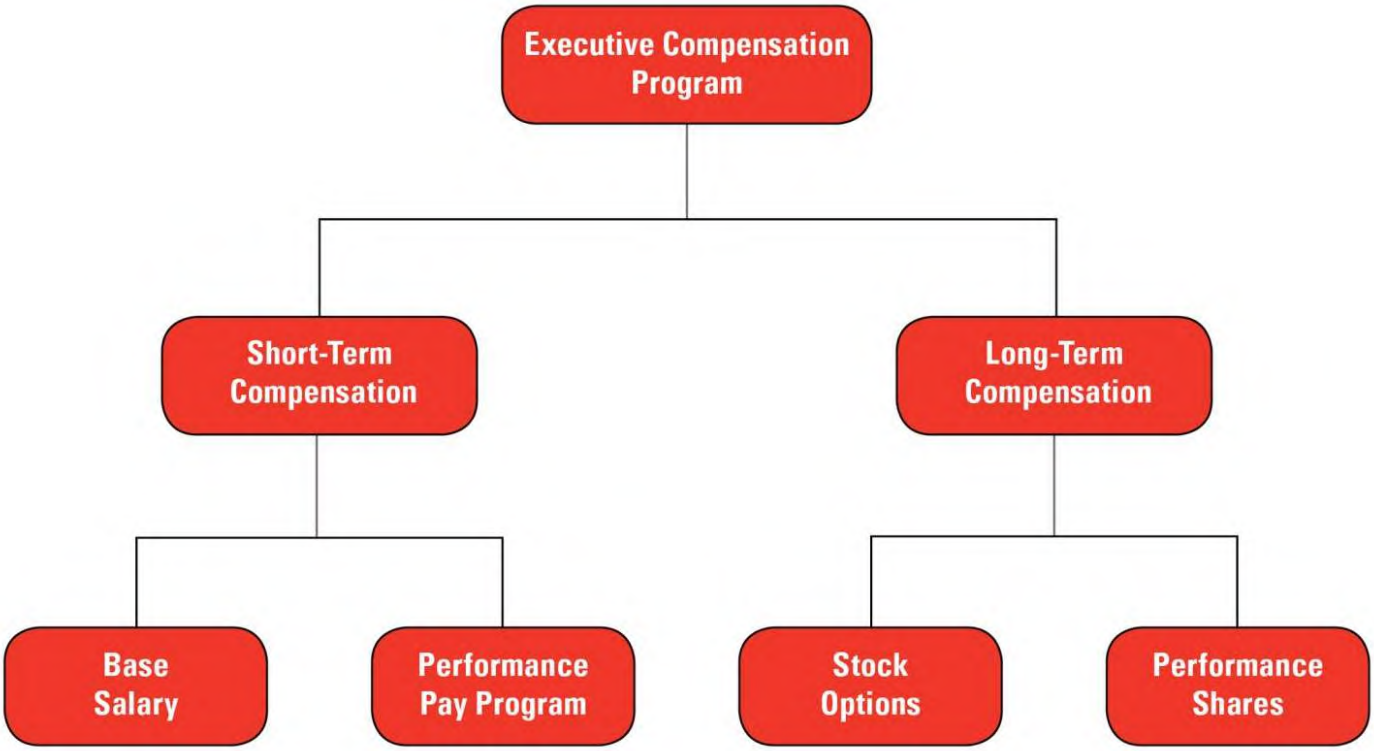
- Business unit financial and operational performance and Southern Company EPS, based on actual results compared to target performance levels established early in the year, determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Southern Company Common Stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company's total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control.

The pay-for-performance principles apply not only to the named executive officers, but to hundreds of Gulf Power's employees. The Performance Pay Program covers almost all of the more than 1,300 employees of Gulf Power. Stock options and performance shares were granted to over 125 employees of Gulf Power. These programs engage employees, which ultimately is good not only for them, but also for Gulf Power's customers and Southern Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The primary components of the 2014 executive compensation program are shown below:



Gulf Power's executive compensation program consists of a combination of short-term and long-term components. Short-term compensation includes base salary and the Performance Pay Program. Long-term performance-based compensation includes stock options and performance shares. The performance-based compensation components are linked to Gulf Power's financial and operational performance, Common Stock performance, and Southern Company's total shareholder return. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent directors of Southern Company. The Compensation Committee believes that the executive compensation program is a balanced program that provides market-based compensation and motivates and rewards performance.

ESTABLISHING MARKET-BASED COMPENSATION LEVELS

Pay Governance develops and presents to the Compensation Committee a competitive market-based compensation level for the Gulf Power Chief Executive Officer. Southern Company's Human Resources staff develops competitive market-based compensation levels for the other Gulf Power named executive officers. The market-based compensation levels for both are developed from a size-appropriate energy services executive compensation survey database. The survey participants, listed below, are utilities with revenues of $1 billion or more. The Compensation Committee reviews the data and uses it in establishing market-based compensation levels for the named executive officers.

AGL Resources Inc.	Entergy Corporation	Pepco Holdings, Inc.
Allete, Inc.	EP Energy Corporation	Pinnacle West Capital Corporation
Alliant Energy Corporation	Eversource International	Portland General Electric Company
Ameren Corporation	Exelon Corporation	PPL Corporation
American Electric Power Company, Inc.	FirstEnergy Corp.	Public Service Enterprise Group Inc.
Areva Inc.	First Solar Inc.	PNM Resources Inc.
Atmos Energy Corporation	GDF SUEZ Energy North America, Inc.	Puget Energy, Inc.
Austin Energy	Iberdrola USA, Inc.	Salt River Project
Avista Corporation	Idaho Power Company	Santee Cooper
Bg US Services, Inc.	Integrys Energy Group, Inc.	SCANA Corporation
Black Hills Corporation	JEA	Sempra Energy
Boardwalk Pipeline Partners, L.P.	Kinder Morgan Energy Partners, L.P.	Southwest Gas Corporation
Calpine Corporation	Laclede Group, Inc.	Spectra Energy Corp.
CenterPoint Energy, Inc.	LG&E and KU Energy LLC	TECO Energy, Inc.
Cleco Corporation	Lower Colorado River Authority	Tennessee Valley Authority
CMS Energy Corporation	MDU Resources Group, Inc.	The AES Corporation
Consolidated Edison, Inc.	National Grid USA	The Babcock & Wilcox Company
Dominion Resources, Inc.	Nebraska Public Power District	The Williams Companies, Inc.
DTE Energy Company	New Jersey Resources Corporation	TransCanada Corporation
Duke Energy Corporation	New York Power Authority	Tri-State Generation & Transmission Association, Inc.
Dynegy Inc.	NextEra Energy, Inc.	
Edison International	NiSource Inc.	UGI Corporation
ElectriCities of North Carolina	NorthWestern Corporation	UIL Holdings
Energen Corporation	NRG Energy, Inc.	UNS Energy Corporation
Energy Future Holdings Corp.	OGE Energy Corp.	Vectren Corporation
Energy Solutions, Inc.	Omaha Public Power District	Westar Energy, Inc.
Energy Transfer Partners, L.P.	Oncor Electric Delivery Company LLC	Wisconsin Energy Corporation
EnLink Midstream	Pacific Gas & Electric Company	Xcel Energy Inc.

Market data for the Chief Executive Officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed. When appropriate, the market data is size-adjusted, up or down, to accurately reflect comparable scopes of responsibilities. Based on that data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, annual performance-based compensation at a target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's and Southern Company's performance for the year or period.

A specified weight was not targeted for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2014 compensation amounts. Total target compensation opportunities for senior management as a group, including the named executive officers, are managed to be at the median of the market for companies of similar size in the electric utility industry. Therefore, some executives may be paid above and others below market. This practice allows for differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, differences are not considered to be material and the compensation program is believed to be market-appropriate, as long as senior management as a group is within an appropriate range. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data. The total target compensation opportunity was established in early 2014 for each named executive officer below:

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
S. W. Connally, Jr.	398,242	238,945	517,692	1,154,879
R. S. Teel	253,504	114,077	152,101	519,682
M. L. Burroughs	200,331	80,133	80,103	360,567
J. R. Fletcher	211,255	84,502	84,480	380,237
P. B. Jacob	267,107	120,198	160,246	547,551
B. C. Terry	272,039	122,418	163,191	557,648

The salary levels shown above were not effective until March 2014. Therefore, the salary amounts reported in the Summary Compensation Table are different than the amounts shown above because that table reports actual amounts paid in 2014. The total target compensation opportunity amount shown for Mr. Jacob represents the full amount had he been employed the entire year by Gulf Power. However, the actual amounts Mr. Jacob received for salary and annual performance-based compensation were prorated based on the amount of time he was employed at Gulf Power in 2014. Additionally, the ultimate number of performance shares earned by Mr. Jacob will be prorated based on the time he was employed during the performance period. See the Summary Compensation Table and Grants of Plan-Based Awards in 2014 for more information on the actual compensation amounts Mr. Jacob received.

Mr. Fletcher was employed at Georgia Power as the Vice President of Governmental and Regulatory Affairs prior to his promotion to Vice President at Gulf Power on March 29, 2014. At that time, his base salary and target annual performance-based compensation were increased to $231,324 and $101,343, respectively.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $2.20 per option and performance shares at $37.54 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted was 40% and 60%, respectively, of the long-term value shown above.

In 2013, Pay Governance analyzed the level of actual payouts for 2012 performance under the annual Performance Pay Program made to the named executive officers relative to performance versus peer companies to provide a check on the goal-setting process, including goal levels and associated performance-based pay opportunities. The findings from the analysis were used in establishing performance goals and the associated range of payouts for goal achievement for 2014. That analysis was updated in 2014 by Pay Governance for 2013 performance, and those findings were used in establishing goals for 2015.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2014 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2014.

With the exception of Southern Company executive officers, including Mr. Connally, base salaries for all Southern Company system officers are within a position level with a base salary range that is established by Southern Company Human Resources staff using the market data described above. Each officer is within one of these established position levels based on the scope of responsibilities that most closely resemble the positions included in the market data described above. The base salary level for individual officers is set within the applicable pre-established range. Factors that influence the specific base salary level within the range include the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual’s relative contribution to the achievement of financial and operational goals in prior years.

Base salaries are reviewed annually in February and changes are made effective March 1. The base salary levels established early in the year for the named executive officers were set within the applicable position level salary range and were recommended by the individual named executive officer’s supervisor and approved by Southern Company's Chief Executive Officer. Mr. Connally's base salary increase was approved by the Compensation Committee.

2014 Performance-Based Compensation

This section describes performance-based compensation for 2014.

Achieving Operational and Financial Performance Goals — The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2014, Gulf Power strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices;
- Meeting energy demand with the best economic and environmental choices;
- Southern Company dividend growth;
- Long-term, risk-adjusted Southern Company total shareholder return;
- Achieving net income goals to support the Southern Company financial plan and dividend growth; and
- Financial integrity - an attractive risk-adjusted return and sound financial policy.

The performance-based compensation program is designed to encourage achievement of these goals.

The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers.

2014 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Rewards achievement of annual performance goals:
  - Business unit net income
  - Business unit operational performance
  - Southern Company EPS
- Goals are weighted one-third each
- Performance results range from 0% to 200% of target, based on level of goal achievement

Overview of Program Design

Almost all employees of Gulf Power, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee and include financial and operational goals. In setting goals for pay purposes, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee of the Southern Company Board of Directors, respectively.

- **Business Unit Financial Goal: Net Income**
  For Southern Company's traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income.

- **Business Unit Operational Goals: Varies by business unit**
  For Southern Company's traditional operating companies, including Gulf Power, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, major projects (Georgia Power and Mississippi Power), and culture. Each of these operational goals is explained in more detail under Goal Details below. The level of

achievement for each operational goal is determined according to the respective performance schedule, and the total operational goal performance is determined by the weighted average result. Each business unit has its own operational goals.

- **Southern Company Financial Goal: EPS**
  EPS is defined as Southern Company's net income from ongoing business activities divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial goals, such adjustments typically include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the financial goals were established and of sufficient magnitude to warrant recognition. As reported in Gulf Power's Annual Report on Form 10-K for the year ended December 31, 2013, the Compensation Committee did not follow its usual practice, and the charges taken in 2013 related to Mississippi Power's construction of the Kemper IGCC were not excluded from goal achievement results. Because the charges were not excluded, the payout levels for all employees, including the named executive officers, were reduced significantly in 2013. In 2014, Southern Company recorded pre-tax charges to earnings of $868 million ($536 million after-tax, or $0.59 per share) (2014 Kemper IGCC Charges) due to estimated probable losses relating to the Kemper IGCC. Additionally, Southern Company adjusted its 2014 net income by $17 million after-tax (or $0.02 per share) relating to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision that reversed the Mississippi PSC's March 2013 rate order associated with the Kemper IGCC (together with the 2014 Kemper IGCC Charges, 2014 Kemper IGCC Charges and Adjustments). The Compensation Committee reviewed the impact of the 2014 Kemper IGCC Charges and Adjustments on goal achievement and payout levels for all Southern Company system employees, including the named executive officers. The Compensation Committee determined that, given the action taken last year and the high levels of achievement of other performance goals in 2014, it was not appropriate to reduce payouts earned in 2014 under the broad-based program applicable to all participating employees. Therefore, the Compensation Committee made an adjustment to exclude the impact of the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) from earnings as it relates to the EPS goal payout for most Southern Company system employees.

As described in greater detail below in Calculating Payouts, Mr. Burroughs is paid in part based on the equity-weighted average of the business unit net income results, which includes the net income goal achievement for Mississippi Power. Due to the 2014 Kemper IGCC Charges and Adjustments described above, Mississippi Power recorded a net loss of $328.7 million, resulting in below-threshold performance and would have resulted in no payout associated with the Mississippi Power portion of the net income goal for thousands of employees across the Southern Company system, including Mr. Burroughs, as well as no payout at all for the business unit financial goal for all Mississippi Power employees. With the adjustment made by the Compensation Committee, Mississippi Power's net income for purposes of calculating goal achievement was $224 million. The adjusted net income resulted in a higher payout for the net income goal for all Mississippi Power employees as well as a higher payout associated with the overall equity-weighted average net income results for several thousand other employees across the Southern Company system whose payouts are determined by the equity-weighted average of the business unit net income results, including Mr. Burroughs.

Under the terms of the program, no payout can be made if events occur that impact Southern Company's financial ability to fund the Common Stock dividend. The 2014 Kemper IGCC Charges and Adjustments described above did not have that effect.

Goal Details

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional operating company, including Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affects customer satisfaction.
Reliability	Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.	Reliably delivering power to customers is essential to Gulf Power's operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability are measured as a percentage of time the nuclear plant is operating. The reliability and availability metrics take generation reductions associated with planned outages into consideration.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
Major Projects - Plant Vogtle Units 3 and 4 and Kemper IGCC	The Southern Company system is committed to the safe, compliant, and high-quality construction and licensing of two new nuclear generating units under construction at Georgia Power's Plant Vogtle (Plant Vogtle Units 3 and 4) and the Kemper IGCC, as well as excellence in transition to operations and prudent decision-making related to these two major projects. An executive review committee is in place for each project to assess progress. A combination of subjective and objective measures is considered in assessing the degree of achievement. Final assessments for each project are approved by either Southern Company's Chief Executive Officer or Southern Company's Chief Operating Officer and confirmed by the Nuclear/Operations Committee of Southern Company.	Strategic projects enable the Southern Company system to expand capacity to provide clean, affordable energy to customers across the region.
Safety	Southern Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	Essential for the protection of employees, customers, and communities.
Culture	The culture goal seeks to improve Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.	Supports workforce development efforts and helps to assure diversity of suppliers.

Financial Performance Goals	Description	Why It Is Important
EPS	Southern Company's net income from ongoing business activities divided by average shares outstanding during the year.	Supports commitment to provide Southern Company's stockholders solid, risk-adjusted returns.
Net Income	For the traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income after dividends on preferred and preference stock.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

The range of business unit and Southern Power net income goals and Southern Company EPS goals for 2014 is shown below. Overall Southern Company performance is determined by the equity-weighted average of the business unit net income goal payouts.

Level of Performance	Alabama Power ($, in millions)	Georgia Power ($, in millions)	Gulf Power ($, in millions)	Mississippi Power ($, in millions)*	Southern Power ($, in millions)	EPS ($)*
Maximum	774	1,258	153.0	240.7	175	2.90
Target	717	1,160	140.2	218.6	135	2.76
Threshold	661	1,063	127.4	196.4	95	2.62

*Excluding impact of the 2014 Kemper IGCC Charges and Adjustments.

The ranges of performance levels established for the primary operational goals are detailed below.

Level of Performance	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operations	Safety	Plant Vogtle Units 3 and 4 and Kemper IGCC	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed targets	Industry best	Significantly exceed targets	Greater than 90 th percentile or 5-year company best	Significantly exceed targets	Significant improvement
Target	Top quartile overall	Meet targets	Top quartile	Meet targets	60th percentile	Meet targets	Improvement
Threshold	2nd quartile overall	Significantly below targets	2nd quartile	Significantly below targets	40th percentile	Significantly below targets	Significantly below expectations

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. If goal achievement is below threshold, there is no payout associated with the applicable goal.

2014 Achievement

Actual 2014 goal achievement is shown in the following tables.

Operational Goal Results:
Gulf Power (Ms. Terry and Messrs. Connally, Teel, Burroughs, Fletcher, and Jacob)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	184
Availability	200
Safety	30
Culture	127
Total Gulf Power Operational Goal Performance Factor	149

Southern Company Generation (Mr. Burroughs)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	195
Availability	190
Safety	150
Culture	141
Major Projects - Plant Vogtle Units 3 and 4 Assessment	175
Major Projects - Kemper IGCC Assessment	75
Total Southern Company Generation Operational Goal Performance Factor	168

Georgia Power (Mr. Fletcher)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	172
Availability	200
Safety	80
Culture	137
Major Projects - Plant Vogtle Units 3 and 4 Assessment	175
Total Georgia Power Operational Goal Performance Factor	162

Financial Performance Goal Results:

Goal	Result	Achievement Percentage (%)
Gulf Power Net Income	$140.18	100
Georgia Power Net Income	$1,225.01	166
Southern Power Net Income	$172.30	193
Corporate Net Income Result	Equity-Weighted Average (1)	163
EPS (from ongoing business activities)	$2.80 (2)	176

(1) The Corporate Net Income Result is the equity-weighted average of the business unit net income results, including the net income result for Mississippi Power. Mississippi Power’s net income result for this purpose was impacted by the adjustment for the 2014 Kemper IGCC Charges and Adjustments ($553 million on an after tax basis). Mississippi Power recorded a net loss, as determined in accordance with generally accepted accounting principles in the United States (GAAP), of $328.7 million. Payouts under the Performance Pay Program were determined using a net income performance result that differed from Mississippi Power's net income as determined in accordance with GAAP.

(2) The EPS result shown in the table excludes the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) as described above. EPS, as determined in accordance with GAAP, was $2.19 per share. Payouts under the Performance Pay Program were determined using an EPS performance result that different from EPS as determined in accordance with GAAP.

Calculating Payouts:

All of the named executive officers are paid based on Southern Company EPS performance. With the exception of Messrs. Burroughs and Fletcher, all of the named executive officers are paid based on Gulf Power net income and operational performance. Southern Company Generation officers, including Mr. Burroughs, are paid based on the goal achievement of the traditional operating company supported (60%) and Southern Company Generation (40%). The Southern Company Generation business unit financial goal is based on the equity-weighted average net income payout results of the traditional operating companies and Southern Power. With the exception of the culture and safety goals, Southern Company Generation's operational goal results are the corporate/aggregate operational goal results. Mr. Fletcher's payout is prorated based on the time he was employed at Georgia Power and at Gulf Power. Mr. Jacob's payout is prorated based on the amount of time he was employed at Gulf Power during 2014.

A total performance factor is determined by adding the applicable business unit financial and operational goal performance and the EPS results and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity to determine the payout for each named executive officer. The table below shows the calculation of the total performance factor for each of the named executive officers, based on results shown above.

	Southern Company EPS Result (%) 1/3 weight [1]	Business Unit Financial Goal Result (%) 1/3 weight	Business Unit Operational Goal Result (%) 1/3 weight	Total Performance Factor (%)
S. W. Connally, Jr.	176	100	149	142
R. S. Teel	176	100	149	142
M. L. Burroughs	176	125	156	152
J. R. Fletcher [2]	176	166/100	162/149	168/142
P. B. Jacob	176	100	149	142
B. C. Terry	176	100	149	142

(1) Excluding the impact of the 2014 Kemper IGCC Charges and Adjustments.

(2) Mr. Fletcher was Vice President of Georgia Power until his promotion to Vice President at Gulf Power on March 29, 2014. Under the terms of the program, Mr. Fletcher's Performance Pay Program results were prorated based on the time he served at each company.

The table below shows the pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity (%)	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	60	238,945	142	339,302
R. S. Teel	45	114,077	142	161,989
M. L. Burroughs	40	80,133	152	121,801
J. R. Fletcher [1]	40/45	101,343	147.7	149,633
P. B. Jacob [2]	45	120,198	142	57,008
B. C. Terry	45	122,418	142	173,833

(1) When Mr. Fletcher was promoted in March 2014, his target annual Performance Pay Program percentage was increased from 40% to 45%. His actual payout shown is prorated based on the amount of time he spent in each position.

(2) Mr. Jacob retired from Gulf Power in May 2014. His Performance Pay Program payout was prorated based on the amount of time he was employed in 2014. The target amount shown is his full target had he been employed for the entire year. The actual amount shown is the prorated amount Mr. Jacob received.

Long-Term Performance-Based Compensation

2014 Long-Term Pay Program Highlights

- Stock Options:
  - Reward long-term Common Stock price appreciation
  - Represent 40% of long-term target value
  - Vest over three years
  - Ten-year term
- Performance Shares:
  - Reward Southern Company total shareholder return relative to industry peers and stock price appreciation
  - Represent 60% of long-term target value
  - Three-year performance period
  - Performance results can range from 0% to 200% of target
  - Paid in Common Stock at end of performance period

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers’ total compensation to the interests of Southern Company’s stockholders. Long-term performance-based awards also benefit customers by providing competitive compensation that allows Gulf Power to attract, retain, and engage employees who provide focus on serving customers and delivering safe and reliable electric service.

Southern Company stock options represent 40% of the long-term performance target value and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Southern Company stock options only generate value if the price of the stock appreciates after the grant date, and performance shares reward employees based on Southern Company total shareholder return relative to industry peers, as well as Common Stock price.

The following table shows the grant date fair value of the long-term performance-based awards granted in 2014.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
S. W. Connally, Jr.	207,086	310,606	517,692
R. S. Teel	60,841	91,260	152,101
M. L. Burroughs	32,052	48,051	80,103
J. R. Fletcher	33,801	50,679	84,480
P. B. Jacob	64,106	96,140	160,246
B. C. Terry	65,287	97,904	163,191

Stock Options

Stock options granted have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. For the grants made in 2014 to Mr. Connally, unvested options are forfeited if he retires from Gulf Power or an affiliate of Gulf Power and accepts a position with a peer company within two years of retirement. The grants made to Mr. Jacob vested upon his retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2014, the Black-Scholes value on the grant date was $2.20 per stock option.

Performance Shares

2014-2016 Grant

Performance shares are denominated in units, meaning no actual shares are issued on the grant date. A grant date fair value per unit was determined. For the grants made in 2014, the value per unit was $37.54. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock.

At the end of the three-year performance period (January 1, 2014 through December 31, 2016), the number of units will be adjusted up or down (0% to 200%) based on Southern Company's total shareholder return relative to that of its peers in the Southern Company custom peer group. While in previous years Southern Company's total shareholder return was measured relative to two peer groups (a custom peer group and the Philadelphia Utility Index), the Compensation Committee decided to streamline the performance share peer group for the 2014 grant by eliminating the Philadelphia Utility Index and establishing one custom peer group. The companies in the custom peer group are those that are believed to be most similar to Southern Company in both business model and investors, creating a peer group that is even more aligned with Southern Company's strategy. For performance shares granted in previous years using the dual peer group structure, the final result will be measured using both peer groups as approved by the Compensation Committee at the time of the grant. The custom peer group varies from the Market Data peer group discussed previously due to the timing and criteria of the peer selection process; however, there is significant overlap. The number of performance share units earned will be paid in Common Stock at the end of the three-year performance period. No dividends or dividend equivalents will be paid or earned on the performance share units. The peers in the custom peer group on the grant date are listed in the following table.

Alliant Energy Corporation	Integrys Energy Group
Ameren Corporation	Pepco Holdings, Inc.
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	PPL Corporation
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Wisconsin Energy Corporation
Edison International	Xcel Energy
Eversource International	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2014 through 2016 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher (Maximum)	200
50th percentile (Target)	100
10th percentile (Threshold)	0

Performance shares are not earned until the end of the three-year performance period. A participant who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

2012-2014 Payouts

Performance share grants were made in 2012 with a three-year performance period that ended on December 31, 2014. Based on Southern Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (28% payout) and the custom peer group (0% payout), the payout percentage was 14% of target, which is the average of the two peer groups. The following table shows the target and actual awards of performance shares for the named executive officers.

	Target Performance Shares (#)	Target Value of Performance Shares ($)	Performance Shares Earned (#)	Value of Performance Shares Earned ($)
S. W. Connally, Jr.	1,944	81,629	272	13,358
R. S. Teel	2,049	86,038	287	14,095
M. L. Burroughs	1,081	45,391	151	7,416
J. R. Fletcher	1,136	47,700	159	7,808
P. B. Jacob (1)	2,185	91,748	238	11,688
B. C. Terry	2,199	92,336	308	15,126

(1) The number of performance shares earned by Mr. Jacob is prorated based on the time he was employed at the Southern Company system during the performance period.

Timing of Performance-Based Compensation

As discussed above, the 2014 annual Performance Pay Program goals and the Southern Company total shareholder return goals applicable to performance shares were established early in the year by the Compensation Committee. Annual stock option grants also were made by the Compensation Committee. The establishment of performance-based compensation goals and the granting of equity awards were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2014 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Southern Excellence Awards

Mr. Fletcher received a discretionary award in the amount of $25,000 in recognition of his leadership and superior performance on high-level regulatory matters while employed at Georgia Power in 2014, prior to his employment at Gulf Power.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits.

Retirement Benefits

Generally, all full-time employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Gulf Power also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information.

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has had a supplemental retirement agreement (SRA) with Ms. Terry since 2010. Prior to her employment with the Southern Company system, Ms. Terry provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf Power for 10 years from the effective date of the SRA before vesting in the benefits. This agreement provides a benefit which recognizes the expertise she brought to Gulf Power and provides a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond.

Gulf Power also provides the Deferred Compensation Plan, which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and accompanying information for more information about the Deferred Compensation Plan.

Severance Agreements

In limited circumstances, Gulf Power will provide a severance agreement in exchange for standard legal releases, non-compete agreements, and confidentiality provisions. In connection with Mr. Jacob's retirement in 2014, Gulf Power entered into a severance agreement with Mr. Jacob providing for a severance payment of $667,768, which is included in the Summary Compensation Table.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; *i.e.,* there must be both a change in control and a termination of employment. Severance payment amounts are two times salary plus target Performance Pay Program opportunity for Mr. Connally and one times salary plus Performance Pay Program opportunity for the other named executive officers. No excise tax gross-up would be provided. More information about severance arrangements is included under Potential Payments upon Termination or Change in Control. Change-in-control protections allow executive officers to focus on potential transactions that are in the best interest of shareholders.

Perquisites

Gulf Power provides limited ongoing perquisites to its executive officers, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits. The perquisites provided in 2014, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for the President and Chief Executive Officer, except on certain relocation-related benefits.

PERFORMANCE-BASED COMPENSATION PROGRAM CHANGES FOR 2015

In early 2015, the Compensation Committee made several changes to the performance-based compensation programs, impacting 2015 compensation. These changes affect both the annual Performance Pay Program as well as the long-term performance-based compensation program and are described below.

Annual Performance-Based Pay Program

Beginning in 2015, the annual performance-based pay program will incorporate individual goals for all executive officers of Southern Company, including Mr. Connally. Currently, the goals are equally weighted between the EPS goal, the applicable business unit net income goal, and the applicable business unit operational goals. Starting with the 2015 annual Performance Pay Program goals, the Compensation Committee added an individual goal component (weighted 10%), and changed the weights for the EPS goal and business unit financial and operational goals (weighted 30% each) for Mr. Connally. The other named executive officers were not affected by this change.

Long-Term Performance-Based Compensation

Since 2010, the Southern Company system's long-term performance-based compensation program has included two components: stock options and performance shares. After reviewing current market practices with Pay Governance, the Compensation Committee decided to modify the long-term performance-based compensation program to further align the compensation program with peers in the utility industry and create better alignment of pay with long-term performance. Beginning with long-term performance-based equity grants made in early 2015, the long-term performance-based program consists exclusively of performance shares. The new structure maintains the three-year performance cycle described earlier in this CD&A for performance shares but expands the performance metrics from one (relative total shareholder return) to three metrics. The new program now includes relative total shareholder return (50%), cumulative EPS from ongoing operations over a three-year period (25%), and equity-weighted return on equity (ROE) (25%). Under the new program, dividends will accrue on performance shares throughout the performance period, and eligible new hires and newly promoted employees will receive interim prorated grants of performance shares instead of stock options.

The continued use of relative total shareholder return as a metric in the long-term performance program maintains consistency with the previous program as well as allows Southern Company to measure its performance against a custom group of regulated peers. The new EPS goal measures cumulative EPS from ongoing operations over a three-year period and motivates ongoing earnings growth to support Southern Company's dividends and achievement of strategic financial objectives. The new equity-weighted ROE goal measures traditional operating company performance from ongoing operations over a three-year period and is set to encourage top quartile ROE performance. Both the EPS and ROE goals are subject to a gateway goal focused on Southern Company's credit ratings. If Southern Company fails to meet the credit rating requirements established by the Compensation Committee, there will be no payout associated with the EPS and ROE goals.

EXECUTIVE STOCK OWNERSHIP REQUIREMENTS

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements. All of the named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership. The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
S. W. Connally, Jr.	3 Times	6 Times
R. S. Teel	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
J. R. Fletcher	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement. Newly-promoted officers have approximately five years from the date of their promotion to meet the increased ownership requirements. All of the named executive officers are meeting their respective ownership requirement. Mr. Jacob is retired and is therefore no longer subject to stock ownership requirements.

POLICY ON RECOVERY OF AWARDS

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of Gulf Power knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer must repay the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

POLICY REGARDING HEDGING THE ECONOMIC RISK OF STOCK OWNERSHIP

Southern Company's policy is that employees and outside directors will not trade Southern Company options on the options market and will not engage in short sales.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2014. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

Henry A. Clark III, Chair
David J. Grain
Veronica M. Hagen
William G. Smith, Jr.
Steven R. Specker

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2012, 2013, and 2014 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. W. Connally, Jr.	2014	393,907	—	310,606	207,086	339,302	496,800	25,948	1,773,649
President, Chief Executive Officer, and	2013	372,977	—	293,018	195,363	164,557	54,607	25,602	1,106,124
Director	2012	295,103	24,376	81,629	54,420	249,526	431,809	179,308	1,316,171
R. S. Teel	2014	252,110	—	91,260	60,841	161,989	157,002	17,166	740,368
Vice President and Chief Financial	2013	244,903	—	88,614	59,101	80,895	—	17,004	490,517
Officer	2012	236,882	—	86,038	57,379	143,335	118,474	15,610	657,718
M. L. Burroughs	2014	199,209	—	48,051	32,052	121,801	213,219	9,893	624,225
Vice President	2013	193,498	—	46,656	31,118	59,127	—	11,225	341,624
	2012	187,855	—	45,391	30,269	94,634	204,035	12,218	574,402
J. R. Fletcher	2014	224,547	25,045	50,679	33,801	149,633	273,148	89,971	846,824
Vice President									
P. B. Jacob	2014	94,293	—	96,140	64,106	57,008	316,172	681,567	1,309,286
Former Vice	2013	258,605	—	93,393	62,272	85,236	—	19,033	518,539
President	2012	253,959	—	91,748	61,169	145,616	310,532	16,671	879,695
B. C. Terry	2014	270,543	—	97,904	65,287	173,833	245,578	17,664	870,809
Vice President	2013	262,809	—	95,094	63,419	86,809	—	16,735	524,866
	2012	255,634	—	92,336	61,573	159,332	210,941	16,910	796,726

Column (a)

Mr. Fletcher was not an executive officer of Gulf Power until 2014.

Column (d)

The amount shown for 2014 for Mr. Fletcher represents a Southern Excellence Award as described in the CD&A and the value of a non-cash safety award he received while employed at Georgia Power. All employees of Georgia Power with a perfect individual safety record in the prior year, including Mr. Fletcher, earned a safety award.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2014. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2014. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2016. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2014 to Ms. Terry and Messrs. Connally, Teel, Burroughs, and Fletcher, assuming that the highest level of performance is achieved, is $195,808, $621,212, $182,520, $96,102, and $101,358, respectively (200% of the amount shown in the table). Because Mr. Jacob retired from Gulf Power on May 3, 2014, the maximum amount he could earn is $21,398, which is prorated based on the number of months he was employed during the performance period. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (f)

This column reports the aggregate grant date fair value of stock options granted in the applicable year. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the payouts under the annual Performance Pay Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended on December 31, 2014. The Performance Pay Program is described in detail in the CD&A.

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31, 2012, 2013, and 2014. Because Mr. Jacob retired in 2014, the amount reported for him in 2014 reflects the actual benefits expected to be paid after the measurement date. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates. In general, all of the named executive officers saw an increase in their pension values due to a decrease in discount rates and updated mortality rates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2014, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2013 and December 31, 2014 are:

- Discount rate for the Pension Plan was decreased to 4.20% as of December 31, 2014 from 5.05% as of December 31, 2013,
- Discount rate for the supplemental pension plans was decreased to 3.75% as of December 31, 2014 from 4.50% as of December 31, 2013, and
- Mortality rates for all plans were updated due to the release of new mortality tables.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; severance payments; tax reimbursements; employer contributions in 2014 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Internal Revenue Code of 1986, as amended (Code); and contributions in 2014 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported for 2014 are itemized below.

	Perquisites ($)	Severance Payments ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. W. Connally, Jr.	5,858	—	—	11,709	8,381	25,948
R. S. Teel	4,937	—	314	11,915	—	17,166
M. L. Burroughs	1,203	—	102	8,588	—	9,893
J. R. Fletcher	48,432	—	30,087	11,452	—	89,971
P. B. Jacob	6,997	667,768	1,899	4,903	—	681,567
B. C. Terry	5,446	—	515	11,165	538	17,664

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of a financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits are provided to cover the costs associated with geographic relocation. In 2014, Mr. Fletcher received relocation-related benefits in the amount of $37,322 in connection with his 2014 relocation from Atlanta, Georgia to Pensacola, Florida. This amount was for the shipment of household goods, incidental expenses related to his move, and home sale and home repurchase assistance. Also, as provided in Gulf Power's relocation policy, tax assistance is provided on the taxable relocation benefits. If Mr. Fletcher terminates within two years of his relocation, these amounts must be repaid.

Personal Use of Corporate Aircraft. The Southern Company system has aircraft that are used to facilitate business travel. All flights on these aircraft must have a business purpose, except limited personal use that is associated with business travel is permitted for the President and Chief Executive Officer. The amount reported for such personal use is the incremental cost of providing the benefit, primarily fuel costs. Also, if seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel, and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included. In connection with Mr. Fletcher's relocation from Atlanta, Georgia to Pensacola, Florida, Mr. Connally approved personal use of the corporate aircraft for one round-trip flight per month for six months. The perquisite amount shown for Mr. Fletcher includes $8,847 for this approved use of corporate aircraft.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2014

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2014 by the Compensation Committee.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	(#) (i)	($/Sh) (j)	($) (k)
S. W. Connally, Jr.		2,389	238,945	477,890						
	2/10/2014				82	8,274	16,548			310,606
	2/10/2014							94,130	41.28	207,086
R. S. Teel		1,141	114,077	228,154						
	2/10/2014				24	2,431	4,862			91,260
	2/10/2014							27,655	41.28	60,841
M. L. Burroughs		801	80,133	160,265						
	2/10/2014				12	1,280	2,560			48,051
	2/10/2014							14,569	41.28	32,052
J. R. Fletcher		1,013	101,343	202,686						
	2/10/2014				13	1,350	2,700			50,679
	2/10/2014							15,364	41.28	33,801
P. B. Jacob		401	40,146	80,292						
	2/10/2014				25	2,561	5,122			96,140
	2/10/2014							29,139	41.28	64,106
B. C. Terry		1,224	122,418	244,836						
	2/10/2014				26	2,608	5,216			97,904
	2/10/2014							29,676	41.28	65,287

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2014 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table. The amounts shown for Mr. Jacob are prorated based on the amount of time he was employed at Gulf Power in 2014. The amounts shown for Mr. Fletcher reflect the increase in salary and annual Performance Pay Program opportunity he received after his promotion to Vice President of Gulf Power on March 29, 2014.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2014 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2014 through 2016 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

The number of shares shown for Mr. Jacob reflects the full grant he received in February 2014. However, since Mr. Jacob retired in May 2014, the ultimate number of performance shares he will receive will be prorated based on the number of months he was employed by the Southern Company system during the performance period.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2014, as described in the CD&A, and column (j) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2014. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model.

The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2014 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares) held by or granted to the named executive officers as of December 31, 2014.

Name (a)	Option Awards				Stock Awards	
Name (a)	**Number of Securities Underlying Unexercised Options Exercisable (#) (b)**	**Number of Securities Underlying Unexercised Options Unexercisable (#) (c)**	**Option Exercise Price ($) (d)**	**Option Expiration Date (e)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)**
S. W. Connally, Jr.	8,521	0	35.78	02/18/2018		
	14,392	0	31.39	02/16/2019		
	16,100	0	37.97	02/14/2021		
	10,702	5,351	44.42	02/13/2022		
	22,302	44,603	44.06	02/11/2023		
	0	94,130	41.28	02/10/2024		
					7,235	355,311
					8,274	406,336
R. S. Teel	9,078	0	35.78	02/18/2018		
	9,332	0	31.39	02/16/2019		
	9,629	0	31.17	02/15/2020		
	16,774	0	37.97	02/14/2021		
	11,284	5,642	44.42	02/13/2022		
	6,747	13,493	44.06	02/11/2023		
	0	27,655	41.28	02/10/2024		
					2,188	107,453
					2,431	119,386
M. L. Burroughs	289	0	33.81	02/20/2016		
	1,604	0	36.42	02/19/2017		
	2,610	0	35.78	02/18/2018		
	1,207	0	31.17	02/15/2020		
	8,956	0	37.97	02/14/2021		
	5,953	2,976	44.42	02/13/2022		
	3,553	7,104	44.06	02/11/2023		
	0	14,569	41.28	02/10/2024		
					1,152	56,575
					1,280	62,861
J. R.Fletcher	3,376	0	37.97	02/14/2021		
	6,247	3,124	44.42	02/13/2022		
	3,728	7,456	44.06	02/11/2023		
	0	15,364	41.28	02/10/2024		
					1,209	59,374
					1,350	66,299
P. B. Jacob	0	0				
					2,306	113,248
					2,561	125,771
B. C. Terry	12,918	0	35.78	02/18/2018		

	12,109	6,054	44.42	02/13/2022		
	7,240	14,479	44.06	02/11/2023		
	0	29,676	41.28	02/10/2024		
					2,348	115,310
					2,608	128,079

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2006 through 2011 with expiration dates from 2016 through 2021 were fully vested as of December 31, 2014. The options granted in 2012, 2013, and 2014 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2012	February 13, 2022	February 13, 2015
2013	February 11, 2023	February 11, 2016
2014	February 10, 2024	February 10, 2017

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

In accordance with SEC rules, column (f) reflects the target number of performance shares that can be earned at the end of each three-year performance period (December 31, 2015 and 2016) that were granted in 2013 and 2014, respectively. The performance shares granted for the 2012 through 2014 performance period vested December 31, 2014 and are shown in the Option Exercises and Stock Vested in 2014 table below. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2014 ($49.11). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. The ultimate number of shares earned by Mr. Jacob will be prorated based on the number of months he was employed by the Southern Company system during the performance periods. See further discussion of performance shares in the CD&A. See also Potential Payments upon Termination or Change in Control for more information about the treatment of performance shares under different termination and change-in-control events.

OPTION EXERCISES AND STOCK VESTED IN 2014

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
S. W. Connally, Jr.	21,795	274,917	272	13,358
R. S. Teel	15,265	168,574	287	14,095
M. L. Burroughs	—	—	151	7,416
J. R. Fletcher	6,905	58,915	159	7,808
P. B. Jacob	112,474	758,786	238	11,688
B. C. Terry	39,302	494,815	308	15,126

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2014 and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

Columns (d) and (e)

Column (d) includes the performance shares awarded for the 2012 through 2014 performance period that vested on December 31, 2014. The value reflected in column (e) is derived by multiplying the number of shares in column (d) by the market value of the underlying shares on the vesting date ($49.11).

PENSION BENEFITS AT 2014 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
	Pension Plan	23.17	595,352	0
	SBP-P	23.17	454,047	0
S.W. Connally, Jr.	SERP	23.17	351,143	0
	Pension Plan	14.33	349,590	0
	SBP-P	14.33	42,360	0
R. S. Teel	SERP	14.33	95,548	0
	Pension Plan	22.58	637,373	0
	SBP-P	22.58	64,888	0
M. L. Burroughs	SERP	22.58	133,832	0
	Pension Plan	24.58	585,977	0
	SBP-P	24.58	101,222	0
J. R. Fletcher	SERP	24.58	176,582	0
	Pension Plan	30.75	1,419,925	46,851
	SBP-P	30.75	269,172	28,796
P. B. Jacob	SERP	30.75	263,763	28,218
	Pension Plan	12.50	334,389	0
	SBP-P	12.50	52,591	0
	SERP	12.50	90,190	0
B. C. Terry	SRA	10.00	397,417	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The rates of pay considered for this formula are the base salary rates with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2014 was $260,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation earned each year is added to the base salary rates of pay.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2014, Ms. Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. As of December 31, 2014, all of the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50.

After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal Pension Plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When a SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent.

Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement-eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in *The Wall Street Journal* . If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If a SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP is also an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts, whether or not deferred, to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included under Potential Payments upon Termination or Change in Control.

Supplemental Retirement Agreements (SRA)

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. These supplemental retirement benefits are also unfunded and not tax qualified. Information about the SRA with Ms. Terry is included in the CD&A.

Pension Benefit Assumptions

The following assumptions were used in the present value calculations for all pension benefits:

- Discount rate - 4.20% Pension Plan and 3.75% supplemental plans as of December 31, 2014,
- Retirement date - Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement - RP-2014 with generational projections,
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement - None,
- Form of payment for Pension Benefits:
  - o Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity,
  - o Female retirees: 75% single life annuity; 15% level income annuity; 5% joint and 50% survivor annuity; and 5% joint and 100% survivor annuity,
- Spouse ages - Wives two years younger than their husbands,
- Annual performance-based compensation earned but unpaid as of the measurement date - 130% of target opportunity percentages times base rate of pay for year amount is earned, and
- Installment determination - 3.75% discount rate for single sum calculation and 4.25% prime rate during installment payment period.

For all of the named executive officers, the number of years of credited service for the Pension Plan, the SBP-P, and the SERP is one year less than the number of years of employment.

Columns (d) and (e)

For Mr. Jacob, who retired May 3, 2014, column (d) reflects the actual benefits expected to be paid, and column (e) reflects the actual amount paid under the Pension Plan, the SBP-P, and the SERP in 2014, as described above.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2014 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	—	8,381	6,690	—	127,836
R. S. Teel	—	—	33	—	162
M. L. Burroughs	—	—	—	—	—
J. R. Fletcher	—	—	—	—	—
P. B. Jacob	8,524	—	45,110	49,994	413,995
B. C. Terry	43,405	538	25,998	—	270,397

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred - the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.
The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2014, the rate of return in the Stock Equivalent Account was 25.27%.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in *The Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2014 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2014. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2014 were the amounts that were earned as of December 31, 2013 but not payable until the first quarter of 2014. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2014, but not payable until early 2015. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The following chart shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2014 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2014 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. W. Connally, Jr.	31,742	10,506	42,248
R. S. Teel	—	—	—
M. L. Burroughs	—	—	—
J. R. Fletcher	—	—	—
P. B. Jacob	282,289	23,274	305,563
B. C. Terry	243,752	950	244,702

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers serving as of December 31, 2014 under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2014 and assumes that the price of Common Stock is the closing market price on December 31, 2014.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible - Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation - Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off - Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination - Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability - Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I - Consummation of an acquisition by another entity of 20% or more of Common Stock, or following consummation of a merger with another entity Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II - Consummation of an acquisition by another entity of 35% or more of Common Stock, or following consummation of a merger with another entity Southern Company shareholders own less than 50% of Southern Company surviving the merger.
- Southern Company Termination - Consummation of a merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control - Consummation of an acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, consummation of a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events as described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if retire before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	Prorated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per the benefit administration committee's discretion.	Same as Retirement.
SBP - non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

The following chart describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits (except SRA)	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension-related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
SRA	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Same as Southern Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2014 .

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2014 under the Pension Plan, the SBP-P, the SERP, and, if applicable, an SRA are itemized in the following chart. The amounts shown under the Retirement column are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2014 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the Resignation or Involuntary Termination column are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2014 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefit amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Ms. Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible on December 31, 2014. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2014. Therefore she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

Name		Retirement ($)	Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. W. Connally, Jr.	Pension	n/a	2,182	3,583
	SBP-P	n/a	453,210	58,157
	SERP	n/a	—	44,977
R. S. Teel	Pension	n/a	1,301	2,163
	SBP-P	n/a	42,275	5,510
	SERP	n/a	—	12,428
M. L. Burroughs	Pension	3,657	All plans treated as retiring	2,697
	SBP-P	7,426		7,426
	SERP	15,316		15,316
J. R. Fletcher	Pension	n/a	1,883	3,093
	SBP-P	n/a	101,166	11,468
	SERP	n/a	—	20,006
B. C. Terry	Pension	n/a	1,181	1,940
	SBP-P	n/a	52,331	6,861
	SERP	n/a	—	11,767
	SRA	n/a	—	51,850

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P, the SERP, and the SRA could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2014 following a change-in-control-related event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. W. Connally, Jr.	443,482	342,972	—	786,454
R. S. Teel	41,367	93,310	—	134,677
M. L. Burroughs	74,260	153,162	—	227,422
J. R. Fletcher	98,994	172,695	—	271,689
B. C. Terry	51,207	87,817	386,959	525,983

The pension benefit amounts in the tables above were calculated as of December 31, 2014 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.79% discount rate .

Annual Performance Pay Program
The amount payable if a change in control had occurred on December 31, 2014 is the greater of target or actual performance. Because actual payouts for 2014 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the CD&A .

Stock Options and Performance Shares (Equity Awards)
Equity Awards would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all Equity Awards vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest. There is no payment associated with Equity Awards unless there is a Southern Company Termination and the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. For stock options, the value is the excess of the exercise price and the closing price of Common Stock on December 31, 2014. The value of performance shares is calculated using the closing price of Common Stock on December 31, 2014.

The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity Awards ($)
Name	Stock Options	Performance Shares	Stock Options	Performance Shares	
S. W. Connally, Jr.	144,084	15,509	216,101	15,509	2,459,809
R. S. Teel	46,790	4,619	109,634	4,619	1,270,952
M. L. Burroughs	24,649	2,432	48,821	2,432	510,197
J. R. Fletcher	25,944	2,559	39,295	2,559	384,010
B. C. Terry	50,209	4,956	101,050	4,956	1,049,729

DCP and SBP
The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table .

Healthcare Benefits
Mr. Burroughs is retirement-eligible. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events. Because the other named executive officers were not retirement-eligible at the end of 2014, healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing healthcare insurance premiums for up to a maximum of two years for Ms. Terry and Messrs. Fletcher and Teel is $11,322, $29,563, and $29,563, respectively. The estimated cost of providing healthcare insurance premiums for up to a maximum of three years for Mr. Connally is $46,028 .

Financial Planning Perquisite
An additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement for retirement-eligible named executive officers.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events .

Severance Benefits
The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Mr. Connally and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers. If any portion of the severance amount constitutes an "excess parachute payment" under Section 280G of the Code and is therefore subject to an excise tax, the severance amount will be reduced unless the after-tax "unreduced amount" exceeds the after-tax "reduced amount." Excise tax gross-ups will not be provided on change-in-control severance payments.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2014 in connection with a change in control.

Name	**Severance Amount ($)**
S. W. Connally, Jr.	1,274,374
R. S. Teel	367,581
M. L. Burroughs	280,464
J. R. Fletcher	332,667
B. C. Terry	394,457

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2014, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock or cash.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock or cash upon leaving the board;
- at prime interest which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board **.**

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2014, including amounts deferred in the Director Deferred Compensation Plan. Non-Employee directors do not receive Non-Equity Incentive Plan Compensation or stock option awards, and there is no pension plan for non-employee directors **.**

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Allan G. Bense	24,400	19,500	0	138	44,038
Deborah H. Calder	24,400	19,500	0	79	43,979
William C. Cramer, Jr.	24,400	19,500	0	79	43,979
Julian B. MacQueen	24,400	19,500	0	138	44,038
J. Mort O'Sullivan III	24,400	19,500	0	303	44,203
Michael T. Rehwinkel	24,400	19,500	0	138	44,038
Winston E. Scott	23,200	19,500	0	107	42,807

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.

(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.

(3) Consists of reimbursement for taxes on imputed income associated with gifts and activities provided to attendees at Southern Company system-sponsored events.

COMPENSATION RISK ASSESSMENT

Southern Company reviewed its compensation policies and practices, including those of Gulf Power, and concluded that excessive risk-taking is not encouraged. This conclusion was based on an assessment of the mix of pay components and performance goals, the annual pay/performance analysis by the Compensation Committee's independent consultant, stock ownership requirements, compensation governance practices, and the claw-back provision. The assessment was reviewed with the Compensation Committee.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2014, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or executive officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership (Applicable to Gulf Power only).

Security Ownership of Certain Beneficial Owners . Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power. The number of outstanding shares reported in the table below is as of January 31, 2015.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant: Gulf Power	5,642,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2014. It is based on information furnished by the directors, nominees, and executive officers. The shares beneficially owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares of Common Stock outstanding on December 31, 2014.

		Shares Beneficially Owned Include:	
Name of Directors, Nominees, and Executive Officers	**Shares Beneficially Owned (1)**	**Deferred Stock Units (2)**	**Shares Individuals Have Rights to Acquire Within 60 Days (3)**
S. W. Connally, Jr.	140,553	0	131,046
Allan G. Bense	3,350	0	0
Deborah H. Calder	2,503	1,999	0
William C. Cramer, Jr.	17,460	17,460	0
Julian B. MacQueen	963	—	0
J. Mort O'Sullivan III	3,721	3,721	0
Michael T. Rehwinkel	480	0	0
Winston E. Scott	7,592	0	0
Michael L. Burroughs	40,327	0	35,557
Jim R. Fletcher	32,455	0	29,391
Richard S. Teel	85,092	0	84,451
Bentina C. Terry	81,808	0	73,991
Directors, Nominees, and Executive Officers as a group (13 people)	431,770	23,180	366,319

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.

(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change in control.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons. None.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

Director Independence.

The board of directors of Gulf Power consists of seven non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., Julian B. MacQueen, J. Mort O'Sullivan, III, Michael T. Rehwinkel, and Winston E. Scott) and Mr. Connally.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2014 and 2013:

	2014	2013
	(in thousands)	
Gulf Power		
Audit Fees (1)	$ 1,427	$ 1,395
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	12	—
Total	$ 1,439	$ 1,395
Southern Power		
Audit Fees (1)	$ 1,143	$ 1,159
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	2	—
Total	$ 1,145	$ 1,159

(1) Includes services performed in connection with financing transactions.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2014 and 2013 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

PART IV

Item 15. **EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Chairman, President, and
Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Ann P. Daiss
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco
Jon A. Boscia
Henry A. Clark III
David J. Grain
Veronica M. Hagen
Warren A. Hood, Jr.
Linda P. Hudson
Donald M. James
John D. Johns
Dale E. Klein
William G. Smith, Jr.
Steven R. Specker
Larry D. Thompson
E. Jenner Wood III

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: *Mark A. Crosswhite*
Chairman, President, and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *March 2, 2015*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
Ralph D. Cook
David J. Cooper, Sr.
Anthony A. Joseph
Patricia M. King
James K. Lowder
Malcolm Portera
Robert D. Powers
Catherine J. Randall
C. Dowd Ritter
James H. Sanford
John Cox Webb, IV

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: *W. Paul Bowers*
Chairman, President, and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *March 2, 2015*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

W. Ron Hinson
Executive Vice President, Chief Financial Officer,
and Treasurer
(Principal Financial Officer)

David P. Poroch
Comptroller and Vice President
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.
Anna R. Cablik
Stephen S. Green
Jimmy C. Tallent
Charles K. Tarbutton
Beverly Daniel Tatum
D. Gary Thompson
Clyde C. Tuggle
Richard W. Ussery

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *March 2, 2015*

GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: *S. W. Connally, Jr.*
President and Chief Executive Officer

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: *March 2, 2015*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

S. W. Connally, Jr.
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense
Deborah H. Calder
William C. Cramer, Jr.
Julian B. MacQueen
J. Mort O'Sullivan, III
Michael T. Rehwinkel
Winston E. Scott

By: */s/Melissa K. Caen*
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: G. Edison Holland, Jr.
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

G. Edison Holland, Jr.
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney	*Christine L. Pickering*
L. Royce Cumbest	*Phillip J. Terrell*
Thomas A. Dews	*M. L. Waters*
Mark E. Keenum	

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Oscar C. Harper IV
President and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

William C. Grantham
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Elliott L. Spencer
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie
Thomas A. Fanning
Kimberly S. Greene
James Y. Kerr II
Mark S. Lantrip
Christopher C. Womack

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of the registrant during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

R EPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the Company) as of December 31, 2014 and 2013 , and for each of the three years in the period ended December 31, 2014 , and the Company's internal control over financial reporting as of December 31, 2014 , and have issued our report thereon dated March 2, 2015 ; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the financial statements of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and for each of the three years in the period ended December 31, 2014 , and have issued our report thereon dated March 2, 2015 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Birmingham, Alabama
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the financial statements of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and for each of the three years in the period ended December 31, 2014 , and have issued our report thereon dated March 2, 2015 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the financial statements of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and for each of the three years in the period ended December 31, 2014 , and have issued our report thereon dated March 2, 2015 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013 , and for each of the three years in the period ended December 31, 2014 , and have issued our report thereon dated March 2, 2015 ; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2014 . Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014 , 2013 , AND 2012
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$ 17,855	$ 43,537	$ —	$ 43,139	$ 18,253
2013	16,984	36,788	—	35,917	17,855
2012	26,155	35,305	—	44,476	16,984

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014 , 2013 , AND 2012
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$ 8,350	$ 14,309	$ —	$ 13,516	$ 9,143
2013	8,450	12,327	—	12,427	8,350
2012	9,856	10,537	—	11,943	8,450

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014 , 2013 , AND 2012
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$ 5,074	$ 24,141	$ —	$ 23,139	$ 6,076
2013	6,259	18,362	—	19,547	5,074
2012	13,038	20,995	—	27,774	6,259

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014 , 2013 , AND 2012
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$ 1,131	$ 4,304	$ —	$ 3,348	$ 2,087
2013	1,490	1,900	—	2,259	1,131
2012	1,962	2,611	—	3,083	1,490

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014 , 2013 , AND 2012
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$ 3,018	$ 562	$ —	$ 2,755	$ 825
2013	373	3,757	—	1,112	3,018
2012	547	628	—	802	373

(Note) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(3) Articles of Incorporation and By-Laws

Southern Company

(a)	1	—	Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)
(a)	2	—	By-laws of Southern Company as amended effective February 11, 2013, and as presently in effect. (Designated in Form 8-K dated February 11, 2013, File No. 1-3526, as Exhibit 3.1.)

Alabama Power

(b)	1	—	Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)
(b)	2	—	Amended and Restated By-laws of Alabama Power effective February 10, 2014, and as presently in effect. (Designated in Form 8-K dated February 10, 2014, File No 1-3164, as Exhibit 3.1.)

Georgia Power

(c)	1	—	Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)
(c)	2	—	By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d)	1	—	Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through June 17, 2013. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 001-31737, as Exhibit 4.7, in Form 8-K dated October 16, 2007, File No. 001-31737, as Exhibit 4.5, and in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.7.)
(d)	2	—	By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.2.)

Mississippi Power

(e)	1	—	Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)
(e)	2	—	By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 001-11229, as Exhibit 3(e)2.)

Southern Power

(f)	1	—	Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)
(f)	2	—	By-laws of Southern Power Company effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company, such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a)	1	—	Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through August 22, 2014. (Designated in Form 8-K dated January 11, 2007, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 21, 2013, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibits 4.2(a) and 4.2(b).)

Alabama Power

(b)	1	—	Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b)	2	—	Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through August 26, 2014. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 3, 2013, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated August 20, 2014, File No. 1-3164, as Exhibit 4.6.)
(b)	3	—	Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)
(b)	4	—	Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c)	1	—	Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through August 16, 2013. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated August 7, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 8, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated August 12, 2013, File No. 1-6468, as Exhibit 4.2.)
(c)	2	—	Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1.)
(c)	3	—	Note Purchase Agreement among Georgia Power, the DOE, and the Federal Financing Bank dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.2.)
(c)	4	—	Future Advance Promissory Note dated February 20, 2014 made by Georgia Power to the FFB. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.3.)
(c)	5	—	Deed to Secure Debt, Security Agreement and Fixture Filing between Georgia Power and PNC Bank, National Association, doing business as Midland Loan Services Inc., a division of PNC Bank, National Association dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.4.)
(c)	6	—	Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power, OPC, MEAG Power, and Dalton dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.5.)

Gulf Power

	(d)	1	—	Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through September 23, 2014. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 12, 2011, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated September 16, 2014, File No. 001-31737, as Exhibit 4.2.)

Mississippi Power

	(e)	1	—	Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)

Southern Power

	(f)	1	—	Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through July 16, 2013. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power Company's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4, and in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4.)

(10) Material Contracts

Southern Company

#	(a)	1	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. (Designated in Southern Company's Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)
#	(a)	2	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	3	—	Deferred Compensation Plan for Outside Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)

#	(a)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)
#	(a)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)
#	(a)	7	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	8	—	Amendment to Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective February 10, 2014. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 10(a)9.)
#	(a)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	10	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	14	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
# *	(a)	15	—	Base Salaries of Named Executive Officers.
#	(a)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 8-K dated February 10, 2014, File No. 1-3526, as Exhibit 10.1.)
# *	(a)	17	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan.
#	(a)	18	—	Retention and Restricted Stock Unit Award Agreement between Southern Nuclear and Stephen E. Kuczynski effective as of July 11, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2013, File No. 1-3526, as Exhibit 10(a)3).)

Alabama Power

	(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10 (a)1 herein.
#	(b)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(b)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(b)	8	—	Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(b)	10	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(b)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10 (a)11 herein.
#	(b)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(b)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(b)	14	—	Base Salaries of Named Executive Officers.
#	(b)	15	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(b)	17	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b) 2.)
#	(b)	18	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. See Exhibit 10(a)7 herein.
#	(b)	19	—	Amendment to Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective February 10, 2014. See Exhibit 10(a)8 herein.

#	(b)	20	—	Retention Award Agreement between Alabama Power and Steven R. Spencer effective July 15, 2013. (Designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-3164, as Exhibit 10(b)1.)
Georgia Power				
	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(c)	2	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10 (a)1 herein.
#	(c)	6	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c)	7	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(c)	10	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(c)	11	—	Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)
#	(c)	12	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(c)	13	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(c)	14	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10 (a)11 herein.
#	(c)	15	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(c)	16	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(c)	17	—	Base Salaries of Named Executive Officers.
#	(c)	18	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)26.)

	(c)	19	—	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, Amendment No. 4 thereto dated as of May 2, 2011, Amendment No. 5 thereto dated as of February 7, 2012, and Amendment No. 6 thereto dated as of January 23, 2014. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, in Georgia Power's Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2014, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	20	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(c)	21	—	Retention Award Agreement and Amendment thereto between Southern Nuclear and Joseph A. Miller, effective January 1, 2013. (Designated in Form 10-K for the year ended December 31, 2012, File No. 1-6468, as Exhibits 10(c)24 and 10(c)25.)

Gulf Power

	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
#	(d)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10 (a)1 herein.
#	(d)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(d)	5	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	6	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(d)	7	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(d)	8	—	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(d)	10	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(d)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10 (a)11 herein.

#	(d)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(d)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(d)	14	—	Base Salaries of Named Executive Officers.
#	(d)	15	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10(d)1.)
#	(d)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(d)	17	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	18	—	Separation and Release Agreement between P. Bernard Jacob and Gulf Power effective May 2, 2014. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2014, File No. 001-31737, as Exhibit 10(d)1.)
Mississippi Power				
	(e)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(e)	2	—	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10 (a)1 herein.
#	(e)	4	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(e)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(e)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(e)	9	—	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(e)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.

#	(e)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(e)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(e)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(e)	15	—	Base Salaries of Named Executive Officers.
#	(e)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)
	(e)	17	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)
#	(e)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(e)	19	—	Consulting Agreement between Mississippi Power and Edward Day, VI effective May 20, 2013. (Designated in Form 10-Q for the quarter ended June 30, 2013, File No. 001-11229, as Exhibit 10(e)1.)
#	(e)	20	—	Amended Deferred Compensation Agreement, effective December 31, 2008 between Southern Company, SCS, Georgia Power, Gulf Power and G. Edison Holland, Jr. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 001-11229, as Exhibit 10(a)2.)
Southern Power				
	(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power Company. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)
	(f)	2	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.

(14) Code of Ethics

Southern Company			
	(a)	—	The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 14(a).)
Alabama Power			
	(b)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Georgia Power			
	(c)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Gulf Power			
	(d)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Mississippi Power			
	(e)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Southern Power			
	(f)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

*	(a)		—	Subsidiaries of Registrant.

Alabama Power

	(b)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

	(c)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

	(d)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

	(e)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

(23) Consents of Experts and Counsel

Southern Company

*	(a)	1	—	Consent of Deloitte & Touche LLP.

Alabama Power

*	(b)	1	—	Consent of Deloitte & Touche LLP.

Georgia Power

*	(c)	1	—	Consent of Deloitte & Touche LLP.

Gulf Power

*	(d)	1	—	Consent of Deloitte & Touche LLP.

Mississippi Power

*	(e)	1	—	Consent of Deloitte & Touche LLP.

Southern Power

*	(f)	1	—	Consent of Deloitte & Touche LLP.

(24) Powers of Attorney and Resolutions

Southern Company

*	(a)		—	Power of Attorney and resolution.

Alabama Power

*	(b)		—	Power of Attorney and resolution.

Georgia Power

*	(c)		—	Power of Attorney and resolution.

Gulf Power

*	(d)		—	Power of Attorney and resolution.

Mississippi Power

*	(e)		—	Power of Attorney and resolution.

Southern Power

*	(f)		—	Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

*	(a)	1	—	Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(a)	2	—	Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	1	—	Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

*	(b)	2	—	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Georgia Power				
*	(c)	1	—	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	—	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Gulf Power				
*	(d)	1	—	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Mississippi Power				
*	(e)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Southern Power				
*	(f)	1	—	Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company			
*	(a)	—	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Alabama Power			
*	(b)	—	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Georgia Power			
*	(c)	—	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Gulf Power			
*	(d)	—	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Mississippi Power			
*	(e)	—	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Southern Power			
*	(f)	—	Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

*	INS	—	XBRL Instance Document
*	SCH	—	XBRL Taxonomy Extension Schema Document
*	CAL	—	XBRL Taxonomy Calculation Linkbase Document
*	DEF	—	XBRL Definition Linkbase Document
*	LAB	—	XBRL Taxonomy Label Linkbase Document
*	PRE	—	XBRL Taxonomy Presentation Linkbase Document

Exhibit 10(a)15

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

THE SOUTHERN COMPANY

The following are the annual base salaries, effective March 1, 2015, unless otherwise noted, of the Chief Executive Officer and Chief Financial Officer of The Southern Company (the "Company") and certain other executive officers of the Company who served during 2014.

Thomas A. Fanning Chairman, President and Chief Executive Officer	$1,250,000
Art P. Beattie Executive Vice President and Chief Financial Officer	$700,438
W. Paul Bowers Executive Vice President of the Company, President and Chief Executive Officer of Georgia Power Company	$814,895
Kimberly S. Greene Executive Vice President and Chief Operating Officer	$666,250
Charles D. McCrary* Executive Vice President of the Company, President and Chief Executive Officer of Alabama Power Company	$803,247

* Retired May 1, 2014. Salary shown was Mr. McCrary's salary effective March 1, 2014.

SOUTHERN COMPANY
OMNIBUS INCENTIVE COMPENSATION PLAN
FORM OF TERMS
PERFORMANCE SHARE AWARD

A Performance Share Award is subject to the following terms and conditions:

1. **Award:** A target number of units ("Performance Shares" or "Performance Share Awards") are awarded by the Compensation and Management Succession Committee ("Committee") of The Southern Company ("Company") board of directors which provides an opportunity to earn an award over a designated Performance Period if certain performance goal measures are met as set forth in Exhibit 1 attached hereto. Performance Share Awards are governed by the Southern Company Omnibus Incentive Compensation Plan, as amended from time to time ("Plan").

2. **Terms and Conditions:** The Performance Share Program Design Details (the "Design Details"), an administrative document adopted by the Committee which is set forth at https:/mysource.southernco.com, contains additional provisions that apply to Performance Share Awards. Additionally, Performance Share Awards are subject to all of the terms and conditions set forth in the Plan and any other administrative documents adopted by the Committee. If there is any inconsistency between the key terms herein and the terms of the Plan or any administrative document adopted by the Committee, the Plan's terms and the administrative document's terms will supersede and replace the conflicting terms of this Form of Terms.

3. **Number of Target Performance Shares:** A target number of Performance Shares awarded to a participant shall be determined by the Committee and allocated among the goals established by the Committee as described in Exhibit 1. The target number of Performance Shares granted will be treated as if dividends are paid and reinvested throughout the Performance Period.

4. **Performance Period:** The period during which the performance goal measures apply ("Performance Period") shall be determined by the Committee at the time awards are made to participants.

5. **Performance Goal Measures:** The performance goal measures will be established by the Committee early in the first year of the Performance Period. At the end of the Performance Period, Employee shall receive between 0% and 200% of the Performance Share Award, as adjusted to reflect deemed dividend reinvestment, depending on Company performance measured against certain performance goals approved by the Committee as described in Exhibit 1. Prior to the final payout, the Committee shall certify that the requirements necessary to receive a payout under each performance goal have been met. Each goal result will be determined and a payout percentage determined. Payout for performance between points is interpolated on a straight-line basis.

6. **Vesting.** The Performance Share Award does not vest until the last day of the Performance Period (Vesting Date). Employee must be employed on the Vesting Date to receive payment, except in the case of death (prorated based on the months of actual employment during the Performance Period) or retirement (no proration). Termination for cause (as defined in the Plan) creates an exception to the vesting rule. Termination for cause (as defined and determined by the Committee) results in forfeiture of any unpaid award, even if vested. See the Design Details for additional information on the impact of certain employment events on the vesting of Performance Share Awards.

7. **Form and Timing of Payout:** Performance Share Awards will be paid in unrestricted shares of common stock of the Company ("Common Stock") as soon as practical following the end of the Performance Period (but in no event later than March 15 immediately following the end of the Performance Period). The value of the Common Stock transferred to a participant for purposes of tax calculations will be determined based on the market price at that time. If the payout date is on a day the New York Stock Exchange is closed, then the market price on the next following business day will be used. The Performance Share Award payout is subject to withholding taxes and thus the actual number of shares a participant may receive will be reduced by the number of shares reflecting the amount of withholding taxes.

8. **Deferral of Payout.** Participants in the Southern Company Deferred Compensation Plan may not defer receipt of Performance Share Award payouts.

9. **Transferability and Share Ownership.** Performance Shares are not transferable or assignable in any manner. A participant is not considered to own any shares of Common Stock based on the Performance Share Award until after performance is measured following the end of the Performance Period and the Performance Shares vest and Common Stock is issued to a participant.

10. **No right to employment.** Neither a Performance Share Award nor this Form of Terms creates any right to employment or continuation of current employment or the right to any future awards under the Plan. No provision of this Form of Terms shall be construed to affect in any manner the existing rights of the Company or its affiliates to suspend, terminate, alter or modify, whether or not for cause, the Employee's employment relationship with the Company or its affiliates.

11. **Impact on other plans.** Neither the Performance Share Award nor the final payout of the Performance Share Award in Common Stock is considered "Compensation" for purposes of the Southern Company Employee Savings Plan or 'Earnings" as defined in The Southern Company Pension Plan. Payments to Employee shall not be considered wages, salary or compensation under any other Company-sponsored employee benefit or compensation plan or program, unless the explicit terms of such plan or program provide otherwise.

Exhibit 1 - Performance Goals

1. Performance Measures. The ultimate amount of Common Stock earned by Employee under this Performance Share Award is based on the achievement of three separate performance goals established by the Committee.

    a. Company Relative Total Shareholder Return (TSR) measures Company stock price performance plus dividends relative to a peer group approved by the Committee. Relative TSR performance accounts for 50% of Employee's target number of Performance Shares granted.
    b. Company Earnings Per Share (EPS) measures cumulative EPS throughout the performance period. EPS performance accounts for 25% of Employee's target number of Performance Shares granted.
    c. Return on Equity (ROE) measures the equity-weighted ROE of the traditional operating companies of the Company during the performance period. ROE performance accounts for 25% of Employee's target number of Performance Shares granted.

2. Credit Quality Threshold Goals . The EPS and ROE goals described above are both subject to credit quality threshold goals established by the Committee at the time of the grant. If, at the end of the performance period, the credit ratings for the Company, Alabama Power Company and Georgia Power Company are below specified levels approved by the Committee, there will be no payout associated with either the EPS or the ROE goals.

EXHIBIT 10(b)14

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

ALABAMA POWER COMPANY

The following are the annual base salaries, effective March 1, 2015, unless otherwise noted, of the Chief Executive Officer and Chief Financial Officer of Alabama Power Company and certain other executive officers of Alabama Power Company who served during 2014.

Charles D. McCrary* President and Chief Executive Officer; Executive Vice President of Southern Company	$803,247
Mark A. Crosswhite President and Chief Executive Officer Executive Vice President of Southern Company	$641,609
Philip C. Raymond Executive Vice President, Chief Financial Officer, and Treasurer	$364,898
James P. Heilbron Senior Vice President and Senior Production Officer	$252,363
Zeke W. Smith Executive Vice President	$364,911
Steven R. Spencer Executive Vice President	$488,760

* Retired May 1, 2014. Salary shown was Mr. McCrary’s salary effective March 1, 2014.

EXHIBIT 10(c)17

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

GEORGIA POWER COMPANY

The following are the annual base salaries, effective March 1, 2015 of the Chief Executive Officer and Chief Financial Officer of Georgia Power Company and certain other executive officers of Georgia Power Company who served during 2014.

W. Paul Bowers President and Chief Executive Officer	$814,895
W. Ron Hinson Executive Vice President, Chief Financial Officer And Treasurer	$372,254
W. Craig Barrs Executive Vice President	$337,777
Joseph A. Miller Executive Vice President	$567,582
Anthony L. Wilson Executive Vice President	$368,280

EXHIBIT 10(d)14

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

GULF POWER COMPANY

The following are the annual base salaries, effective March 1, 2015, unless otherwise noted, of the Chief Executive Officer and Chief Financial Officer of Gulf Power Company and certain other executive officers of Gulf Power Company who served during 2014.

S. W. Connally, Jr. President and Chief Executive Officer	$426,119
Richard S. Teel Vice President and Chief Financial Officer	$261,168
P. Bernard Jacob* Vice President	$267,107
Michael L. Burroughs Vice President	$208,345
Bentina C. Terry Vice President	$280,264

* Retired May 3, 2014. Salary shown was Mr. Jacob's salary effective March 1, 2014.

EXHIBIT 10(e)15

BASE SALARIES OF NAMED EXECUTIVE OFFICERS

MISSISSIPPI POWER COMPANY

The following are the annual base salaries, effective March 1, 2015, unless otherwise noted, of the Chief Executive Officer and Chief Financial Officer of Mississippi Power Company and certain other executive officers of Mississippi Power Company who served during 2014.

G. Edison Holland, Jr. President and Chief Executive Officer	$678,480
Moses Feagin Vice President, Treasurer and Chief Financial Officer	$263,280
John W. Atherton Vice President	$267,651
Jeff G. Franklin Vice President	$265,125
John C. Huggins* Vice President	$212,513

* Retired February 20, 2015. Salary shown was Mr. Huggins' salary effective March 1, 2014.

Exhibit 21(a)

Subsidiaries of the Registrant*

Name of Company	Jurisdiction of Organization
The Southern Company	Delaware
Southern Company Holdings, Inc.	Delaware
Alabama Power Company	Alabama
Alabama Power Capital Trust V	Delaware
Alabama Property Company	Alabama
Southern Electric Generating Company	Alabama
Georgia Power Company	Georgia
Piedmont-Forrest Corporation	Georgia
Southern Electric Generating Company	Alabama
Gulf Power Company	Florida
Mississippi Power Company	Mississippi
Southern Power Company**	Delaware

*This information is as of December 31, 2014. In addition, this list omits certain subsidiaries pursuant to paragraph (b)(21)(ii) of Regulation S-K, Item 601.

**Southern Power Company has omitted its list of subsidiaries in accordance with General Instruction I(2)(b) of Form 10-K.

Exhibit 23(a)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-78617, 33-54415, 33-58371, 33-60427, 333-44127, 333-118061, 333-166709, 333-174704, 333-174707, and 333-179779 on Form S-8 and Registration Statement Nos. 333-179734 and 333-179766 on Form S-3 of our reports dated March 2, 2015, relating to the consolidated financial statements and consolidated financial statement schedule of The Southern Company and Subsidiary Companies, and the effectiveness of The Southern Company and Subsidiary Companies' internal control over financial reporting, appearing in this Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

Exhibit 23(b)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-194227 on Form S-3 of our reports dated March 2, 2015, relating to the financial statements and financial statement schedule of Alabama Power Company, appearing in this Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Birmingham, Alabama
March 2, 2015

Exhibit 23(c)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-186969 on Form S-3 of our reports dated March 2, 2015, relating to the financial statements and financial statement schedule of Georgia Power Company, appearing in this Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

Exhibit 23(d)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-188623 on Form S-3 of our reports dated March 2, 2015, relating to the financial statements and financial statement schedule of Gulf Power Company, appearing in this Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

Exhibit 23(e)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-183528 (as amended) on Form S-3 of our reports dated March 2, 2015, relating to the financial statements and financial statement schedule of Mississippi Power Company, appearing in this Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

Exhibit 23(f)1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-184850 on Form S-3 of our report dated March 2, 2015, relating to the consolidated financial statements of Southern Power Company and Subsidiary Companies, appearing in this Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

Exhibit 24(a)

February 9, 2015

Melissa K. Caen and Matthew D. Bozzelli

Ms. Caen and Mr. Bozzelli:

The Southern Company (the “Company”) proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2014 and (2) the Company’s Quarterly Reports on Form 10-Q during 2015.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

THE SOUTHERN COMPANY

By /s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Juanita Powell Baranco
Juanita Powell Baranco

/s/Jon A. Boscia
Jon A. Boscia

/s/Henry A. Clark III
Henry A. Clark III

/s/Thomas A. Fanning
Thomas A. Fanning

/s/David J. Grain
David J. Grain

/s/Veronica M. Hagen
Veronica M. Hagen

/s/Warren A. Hood, Jr.
Warren A. Hood, Jr.

/s/Linda P. Hudson
Linda P. Hudson

/s/Donald M. James
Donald M. James

/s/John D. Johns
John D. Johns

/s/Dale E. Klein
Dale E. Klein

/s/William G. Smith, Jr.
William G. Smith, Jr.

/s/Steven R. Specker
Steven R. Specker

/s/Larry D. Thompson
Larry D. Thompson

/s/E. Jenner Wood III
E. Jenner Wood III

/s/Art P. Beattie
Art P. Beattie

/s/Ann P. Daiss
Ann P. Daiss

Extract from minutes of meeting of the board of directors of The Southern Company.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and its 2015 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its Board of Directors and its officers be and hereby are authorized to give their several powers of attorney to Melissa K. Caen and Matthew D. Bozzelli.

- - - - - - - - - -

The undersigned officer of The Southern Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of The Southern Company, duly held on February 9, 2015, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: March 2, 2015

THE SOUTHERN COMPANY

By /s/Melissa K.Caen

Melissa K. Caen
Corporate Secretary

Exhibit 24(b)

600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291-0001

Tel 205.257.1000

January 23, 2015

Art P. Beattie
30 Ivan Allen Jr. Blvd., N.W
Atlanta, Georgia 30308

Melissa K. Caen
30 Ivan Allen Jr. Blvd., N.W.
Atlanta, Georgia 30308

Dear Mr. Beattie and Ms. Caen:

Alabama Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and (2) the Company's Quarterly Reports on Form 10-Q during 2015.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,
ALABAMA POWER COMPANY
By /s/Mark A. Crosswhite
Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Whit Armstrong
Whit Armstrong

/s/Ralph D. Cook
Ralph D. Cook

/s/David J. Cooper, Sr.
David J. Cooper, Sr.

/s/Mark A. Crosswhite
Mark A. Crosswhite

/s/Thomas A. Fanning
Thomas A. Fanning

/s/John D. Johns
John D. Johns

/s/Patricia M. King
Patricia M. King

/s/Catherine J. Randall
Catherine J. Randall

/s/Anita Allcorn-Walker
Anita Allcorn-Walker

/s/James K. Lowder
James K. Lowder

/s/Malcolm Portera
Malcolm Portera

/s/Robert D. Powers
Robert D. Powers

/s/C. Dowd Ritter
C. Dowd Ritter

/s/James H. Sanford
James H. Sanford

/s/John Cox Webb, IV
John Cox Webb, IV

/s/Anthony A. Joseph
Anthony A. Joseph

/s/Philip C. Raymond
Philip C. Raymond

Extract from minutes of meeting of the board of directors of Alabama Power Company.

- - - - - - - - - -

RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2014 and its 2015 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, this Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Alabama Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Alabama Power Company, duly held on January 23, 2015, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: March 2, 2015

ALABAMA POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(c)

February 18, 2015

W. Ron Hinson, David P. Poroch, Art P. Beattie and Melissa K. Caen

Lady and Gentlemen:

Georgia Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and (2) the Company's Quarterly Reports on Form 10-Q during 2015.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

GEORGIA POWER COMPANY

By /s/W. Paul Bowers

W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/W. Paul Bowers
W. Paul Bowers

/s/Robert L. Brown, Jr.
Robert L. Brown, Jr.

/s/Anna R. Cablik
Anna R. Cablik

/s/Thomas A. Fanning
Thomas A. Fanning

/s/Stephen S. Green
Stephen S. Green

/s/Jimmy C. Tallent
Jimmy C. Tallent

/s/Charles K. Tarbutton
Charles K. Tarbutton

/s/Beverly Daniel Tatum
Beverly Daniel Tatum

/s/D. Gary Thompson
D. Gary Thompson

/s/Clyde C. Tuggle
Clyde C. Tuggle

/s/Richard W. Ussery
Richard W. Ussery

/s/W. Ron Hinson
W. Ron Hinson

/s/Thomas P. Bishop
Thomas P. Bishop

/s/David P. Poroch
David P. Poroch

Extract from minutes of meeting of the board of directors of Georgia Power Company.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of this Company's Annual Report on Form 10-K for the year ended December 31, 2014 and its 2015 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to W. Ron Hinson, David P. Poroch, Art P. Beattie and Melissa K. Caen.

- - - - - - - - -

The undersigned officer of Georgia Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Georgia Power Company, duly held on February 18, 2015, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: March 2, 2015

GEORGIA POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(d)

One Energy Place
Pensacola, FL 32520

Tel 850-444-6111

GULF POWER
A SOUTHERN COMPANY

October 23, 2014

Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Dear Mr. Beattie and Ms. Caen:

Gulf Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and (2) the Company's Quarterly Reports on Form 10-Q during 2015.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

GULF POWER COMPANY

By /s/S. W. Connally, Jr.
S. W. Connally, Jr.
President and Chief Executive Officer

/s/Allan G. Bense
Allan G. Bense

/s/Deborah H. Calder
Deborah H. Calder

/s/S. W. Connally, Jr.
S. W. Connally, Jr.

/s/William C. Cramer, Jr.
William C. Cramer, Jr.

/s/Julian B. MacQueen
Julian B. MacQueen

/s/J. Mort O'Sullivan, III
J. Mort O'Sullivan, III

/s/Michael T. Rehwinkel
Michael T. Rehwinkel

/s/Winston E. Scott
Winston E. Scott

/s/Richard S. Teel
Richard S. Teel

/s/Janet J. Hodnett
Janet J. Hodnett

/s/Susan D. Ritenour
Susan D. Ritenour

Extract from minutes of meeting of the board of directors of Gulf Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934, as amended, to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and its 2015 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

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The undersigned officer of Gulf Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Gulf Power Company, duly held on October 23, 2014, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: March 2, 2015

GULF POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(e)

October 28, 2014

Mr. Art P. Beattie
The Southern Company
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd., NW
Atlanta, GA 30308

Mr. Beattie and Ms. Caen:

Mississippi Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and (2) the Company's Quarterly Reports on Form 10-Q during 2015.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

MISSISSIPPI POWER COMPANY

By /s/G. Edison Holland, Jr.

G. Edison Holland, Jr.
Chairman, President and
Chief Executive Officer

/s/Carl J. Chaney
Carl J. Chaney

/s/Philip J. Terrell
Philip J. Terrell

/s/L. Royce Cumbest
L. Royce Cumbest

/s/M. L. Waters
M. L. Waters

/s/Thomas A. Dews
Thomas A. Dews

/s/Moses H. Feagin
Moses H. Feagin

/s/G. Edison Holland, Jr.
G. Edison Holland, Jr.

/s/Cynthia F. Shaw
Cynthia F. Shaw

/s/Mark E. Keenum
Mark E. Keenum

/s/Vicki L. Pierce
Vicki L. Pierce

/s/Christine L. Pickering
Christine L. Pickering

Extract from minutes of meeting of the board of directors of Mississippi Power Company.

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RESOLVED, That for the purpose of signing the reports under the Securities Exchange Act of 1934, as amended, to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and its 2015 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Art P. Beattie and Melissa K. Caen.

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The undersigned officer of Mississippi Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Mississippi Power Company, duly held on October 28, 2014, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: March 2, 2015

MISSISSIPPI POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 24(f)

November 17, 2014

Mr. Elliott L. Spencer
Southern Power Company
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Ms. Melissa K. Caen
Southern Company Services, Inc.
30 Ivan Allen Jr. Blvd, NW
Atlanta, GA 30308

Mr. Spencer and Ms. Caen:

Southern Power Company (the "Company") proposes to file or join in the filing of reports under the Securities Exchange Act of 1934, as amended, with the Securities and Exchange Commission with respect to the following: (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and (2) the Company's Quarterly Reports on Form 10-Q during 2015.

The Company and the undersigned directors and officers of the Company, individually as a director and/or as an officer of the Company, hereby make, constitute and appoint each of you our true and lawful Attorney for each of us and in each of our names, places and steads to sign and cause to be filed with the Securities and Exchange Commission in connection with the foregoing said Annual Report on Form 10-K, said Quarterly Reports on Form 10-Q and any necessary or appropriate amendment or amendments to any such reports, to be accompanied in each case by any necessary or appropriate exhibits or schedules thereto.

Yours very truly,

SOUTHERN POWER COMPANY

By /s/Oscar C. Harper IV

Oscar C. Harper IV
President and Chief
Executive Officer

/s/Art P. Beattie
Art P. Beattie

/s/Thomas A. Fanning
Thomas A. Fanning

/s/Kimberly S. Greene
Kimberly S. Greene

/s/Oscar C. Harper IV
Oscar C. Harper IV

/s/James Y. Kerr, II
James Y. Kerr, II

/s/Mark S. Lantrip
Mark S. Lantrip

/s/Christopher C. Womack
Christopher C. Womack

/s/William C. Grantham
William C. Grantham

/s/Elliott L. Spencer
Elliott L. Spencer

Extract from minutes of meeting of the board of directors of Southern Power Company.

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RESOLVED: That for the purpose of signing the reports under the Securities Exchange Act of 1934 to be filed with the Securities and Exchange Commission with respect to the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and its 2015 Quarterly Reports on Form 10-Q, and any necessary or appropriate amendment or amendments to any such reports, the Company, the members of its board of directors and its officers are authorized to give their several powers of attorney to Elliott L. Spencer and Melissa K. Caen.

- - - - - - - - - -

The undersigned officer of Southern Power Company does hereby certify that the foregoing is a true and correct copy of a resolution duly and regularly adopted at a meeting of the board of directors of Southern Power Company, duly held on November 17, 2014, at which a quorum was in attendance and voting throughout, and that said resolution has not since been rescinded but is still in full force and effect.

Dated: March 2, 2015

SOUTHERN POWER COMPANY

By /s/Melissa K. Caen

Melissa K. Caen
Assistant Secretary

Exhibit 31(a)1

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Thomas A. Fanning, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Thomas A. Fanning

Thomas A. Fanning

Chairman, President and
Chief Executive Officer

Exhibit 31(a)2

THE SOUTHERN COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Art P. Beattie, certify that:

1. I have reviewed this annual report on Form 10-K of The Southern Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Art P. Beattie

Art P. Beattie

Executive Vice President and Chief Financial Officer

Exhibit 31(b)1

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Mark A. Crosswhite, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Mark A. Crosswhite

Mark A. Crosswhite
Chairman, President and Chief Executive Officer

Exhibit 31(b)2

ALABAMA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Philip C. Raymond, certify that:

1. I have reviewed this annual report on Form 10-K of Alabama Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Philip C. Raymond

Philip C. Raymond

Executive Vice President, Chief Financial Officer
and Treasurer

Exhibit 31(c)1

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, W. Paul Bowers, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/W. Paul Bowers

W. Paul Bowers

Chairman, President and Chief Executive Officer

Exhibit 31(c)2

GEORGIA POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, W. Ron Hinson, certify that:

1. I have reviewed this annual report on Form 10-K of Georgia Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/W. Ron Hinson

W. Ron Hinson
Executive Vice President, Chief Financial Officer and Treasurer

Exhibit 31(d)1

GULF POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, S. W. Connally, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/S. W. Connally, Jr.

S. W. Connally, Jr.
President and Chief Executive Officer

Exhibit 31(d)2

GULF POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Richard S. Teel, certify that:

1. I have reviewed this annual report on Form 10-K of Gulf Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Richard S. Teel

Richard S. Teel

Vice President and Chief Financial Officer

Exhibit 31(e)1

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, G. Edison Holland, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/G. Edison Holland, Jr.

G. Edison Holland, Jr.
Chairman, President and Chief Executive Officer

Exhibit 31(e)2

MISSISSIPPI POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Moses H. Feagin, certify that:

1. I have reviewed this annual report on Form 10-K of Mississippi Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Moses H. Feagin

Moses H. Feagin

Vice President, Treasurer and
Chief Financial Officer

Exhibit 31(f)1

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Oscar C. Harper IV, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2015

/s/Oscar C. Harper IV

Oscar C. Harper IV

President and Chief Executive Officer

Exhibit 31(f)2

SOUTHERN POWER COMPANY

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, William C. Grantham, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 2, 2015

/s/William C. Grantham

William C. Grantham

Vice President, Treasurer and Chief
Financial Officer

Exhibit 32(a)

CERTIFICATION

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2014, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2014, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of The Southern Company for the year ended December 31, 2014, fairly presents, in all material respects, the financial condition and results of operations of The Southern Company.

/s/Thomas A. Fanning

Thomas A. Fanning
Chairman, President and
Chief Executive Officer

/s/Art P. Beattie

Art P. Beattie
Executive Vice President and
Chief Financial Officer

March 2, 2015

Exhibit 32(b)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2014, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2014, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Alabama Power Company for the year ended December 31, 2014, fairly presents, in all material respects, the financial condition and results of operations of Alabama Power Company.

/s/Mark A. Crosswhite

Mark A. Crosswhite
Chairman, President and Chief Executive Officer

/s/Philip C. Raymond

Philip C. Raymond
Executive Vice President,
Chief Financial Officer and Treasurer

March 2, 2015

Exhibit 32(c)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2014, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2014, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Georgia Power Company for the year ended December 31, 2014, fairly presents, in all material respects, the financial condition and results of operations of Georgia Power Company.

/s/W. Paul Bowers
W. Paul Bowers
Chairman, President and Chief Executive Officer

/s/W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer and Treasurer

March 2, 2015

Exhibit 32(d)

CERTIFICATION

**18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2014, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2014, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Gulf Power Company for the year ended December 31, 2014, fairly presents, in all material respects, the financial condition and results of operations of Gulf Power Company.

/s/S. W. Connally, Jr.
S. W. Connally, Jr.
President and Chief Executive Officer

/s/Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer

March 2, 2015

Exhibit 32(e)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2014, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2014, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Mississippi Power Company for the year ended December 31, 2014, fairly presents, in all material respects, the financial condition and results of operations of Mississippi Power Company.

/s/G. Edison Holland, Jr.
G. Edison Holland, Jr.
Chairman, President and Chief Executive Officer

/s/Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer and
Chief Financial Officer

March 2, 2015

Exhibit 32(f)

CERTIFICATION

18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2014, we, the undersigned, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of our individual knowledge and belief, that:

(1) such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2014, which this statement accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Southern Power Company for the year ended December 31, 2014, fairly presents, in all material respects, the financial condition and results of operations of Southern Power Company.

/s/Oscar C. Harper IV
Oscar C. Harper IV
President and Chief Executive Officer

/s/William C. Grantham
William C. Grantham
Vice President, Treasurer and
Chief Financial Officer

March 2, 2015

Exhibit 9

AGREEMENT AND PLAN OF MERGER

BY

AND

AMONG

THE SOUTHERN COMPANY,

AMS CORP.

AND

AGL RESOURCES INC.

DATED AUGUST 23, 2015

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AGREEMENT AND PLAN OF MERGER

AGREEMENT AND PLAN OF MERGER, dated August 23, 2015 (this "Agreement"), by and among The Southern Company, a Delaware corporation ("Parent"), AMS Corp., a Georgia corporation and Parent Subsidiary ("Merger Sub"), and AGL Resources Inc., a Georgia corporation (the "Company").

RECITALS

A. The Board of Directors of the Company (the "Company Board"), the Board of Directors of Parent (the "Parent Board") and the Board of Directors of Merger Sub have determined that it is in the best interests of their respective companies and shareholders to consummate the strategic business combination transaction provided for in this Agreement in which Merger Sub will, on the terms and subject to the conditions set forth in this Agreement, merge with and into the Company (the "Merger"), with the Company being the surviving corporation in the Merger.

B. The Parties desire to make or enter into certain representations, warranties and covenants in connection with the Merger and also to prescribe certain conditions to the Merger.

Parent, Merger Sub and the Company hereby agree as follows:

ARTICLE I

THE MERGER

Section 1.1 The Merger. On the terms and subject to the conditions set forth in this Agreement, and in accordance with the Georgia Business Corporation Code (the "GBCC"), Merger Sub will be merged with and into the Company at the Effective Time. At the Effective Time, the separate corporate existence of Merger Sub will cease, and the Company will continue as the surviving corporation (the "Surviving Corporation") and will succeed to and assume all the rights and obligations of Merger Sub in accordance with the GBCC.

Section 1.2 Closing. The closing (the "Closing") of the Merger will take place at the offices of Jones Day, 1420 Peachtree Street, N.E., Suite 800, Atlanta, Georgia 30309, at 10:00 a.m. local time on the second Business Day following the satisfaction or, to the extent permitted by Law, waiver of the conditions set forth in Article VII (other than those conditions that by their terms are to be satisfied at the Closing, but subject to the satisfaction or, to the extent permitted by Law, waiver of those conditions at Closing). The date on which the Closing occurs is referred to in this Agreement as the "Closing Date."

Section 1.3 Effective Time. On the Closing Date, Parent, Merger Sub and the Company will cause to be delivered to the Secretary of State of the State of Georgia for filing a certificate of merger or other appropriate documents (collectively, the "Certificate of Merger") executed in accordance with the relevant provisions of the GBCC and will make all other filings or recordings required under the GBCC. The Merger will become effective at such time as the Certificate of Merger is duly filed by such Secretary of State, or at such other time as Parent and the Company will agree and specify in the Certificate of Merger (the time the Merger becomes effective being the "Effective Time").

Section 1.4 Effects. The Merger will have the effects provided in this Agreement and in the applicable provisions of the GBCC.

Section 1.5 Conversion of Securities.

(a) Conversion of Company Common Stock. At the Effective Time, by virtue of the Merger and without any action on the part of Parent, Merger Sub, the Company or the holders of Company Common Stock, each share of Company Common Stock (each, a "Share") issued and outstanding immediately prior to the Effective Time (other than Dissenting Shares and any Shares to be cancelled pursuant to Section 1.5(b)) will be converted automatically into the right to receive, in accordance with the terms of this Agreement, $66.00 in cash (the "Merger Consideration"), payable in the manner set forth in Section 2.1. At the Effective Time and as a result of the Merger, all such Shares will cease to be outstanding, will be cancelled and will cease to exist, and each holder of a certificate or certificates that immediately prior to the Effective Time represented any such outstanding Shares ("Certificates") and each holder of any such Shares outstanding immediately prior to the Effective Time that are not represented by Certificates ("Book-Entry Shares") will thereafter cease to have any rights with respect to such Shares except the right to receive the Merger Consideration, to be paid, without interest, in consideration therefor upon surrender of such Certificate or Book-Entry Shares in accordance with Section 2.1(b) (or in the case of a lost, stolen or destroyed Certificate, Section 2.1(h)).

(b) Cancellation of Certain Shares. At the Effective Time, by virtue of the Merger and without any action on the part of Parent, Merger Sub or the Company, each Share held in the treasury of the Company or owned of record by any Company Subsidiary immediately prior to the Effective Time will automatically be cancelled without any conversion thereof and no payment or distribution will be made with respect thereto.

(c) Shares of Merger Sub. Each issued and outstanding share of common stock, par value $0.01, of Merger Sub will be converted into and become one validly issued, fully paid and nonassessable share of common stock of the Surviving Corporation.

Section 1.6 Articles of Incorporation; Bylaws.

(a) The Company Charter in effect immediately prior to the Effective Time will be the articles of incorporation of the Surviving Corporation, until thereafter amended as provided therein or by applicable Law.

(b) At the Effective Time, the Company Bylaws will, by virtue of the Merger, be amended and restated in their entirety to read as the Merger Sub Bylaws as in effect immediately prior to the Effective Time, and as so amended and restated will be the bylaws of the Surviving Corporation, until thereafter amended as provided therein or by applicable Law.

Section 1.7 Directors. The Parties will take all necessary action such that, from and after the Effective Time, the directors of the Company immediately prior to the Effective Time will become the directors of the Surviving Corporation, until the earlier of their resignation or removal or until their respective successors are duly elected and qualified, as the case may be.

Section 1.8 Officers. The Parties will take all necessary action such that, from and after the Effective Time, the officers of the Company immediately prior to the Effective Time will become the officers of the Surviving Corporation, until the earlier of their resignation or removal or until their respective successors are duly elected or appointed and qualified, as the case may be.

ARTICLE II

DELIVERY OF MERGER CONSIDERATION

Section 2.1 Exchange of Shares.

(a) Exchange Agent. Prior to the Effective Time, Parent will (i) designate a commercial bank or trust company reasonably acceptable to the Company to act as agent (the "Exchange Agent") for the purpose of exchanging Shares for the Merger Consideration and (ii) enter into an agreement reasonably acceptable to the Company with the Exchange Agent relating to the services to be performed by the Exchange Agent. Parent will deposit or will cause to be deposited with the Exchange Agent at or prior to the Effective Time, cash in an amount sufficient to pay the Merger Consideration pursuant to Section 1.5(a) (the "Exchange Fund"). The Exchange Fund will be invested by the Exchange Agent as directed by Parent. Any interest or other income from such investments will be paid to and become income of Parent. The Exchange Fund will not be used for any other purpose. To the extent that there are losses with respect to such investments, or the Exchange Fund diminishes for other reasons below the level required to make prompt cash payment as contemplated to be paid pursuant to this Article II, Parent will promptly replace or restore the cash in the Exchange Fund lost through such investments or other events to ensure that the Exchange Fund is at all times maintained at a level sufficient for the Exchange Agent to promptly make such cash payments.

(b) Exchange Procedures.

(i) As promptly as practicable after the Effective Time, but in any event within two Business Days, Parent will cause the Exchange Agent to mail (and, to the extent commercially practicable, Parent will, or will cause the Exchange Agent to, make available for collection by hand, during customary hours commencing immediately after the Effective Time, if so elected by a holder of Shares) to each Person who was, at the Effective Time, a holder of record of Shares (other than the Depository Trust Company ("DTC")) entitled to receive the Merger Consideration pursuant to Section 1.5(a): (A) a letter of transmittal in customary form and containing such provisions as Parent may reasonably specify (including a provision confirming that delivery will be effected, and risk of loss and title will pass, only upon proper delivery of the Certificates to the Exchange Agent or, in the case of Book-Entry Shares, upon adherence to the procedures set forth in the letter of transmittal), and (B) instructions for use in effecting the surrender of such holder's Certificates or Book-Entry Shares in exchange for payment of the Merger Consideration issuable and payable in respect thereof pursuant to such letter of transmittal; provided, however, that Parent will be required to obtain the Company's approval of such letter of transmittal and instructions prior to the Effective Time (such approval not to be unreasonably withheld). Exchange of any Book-Entry Shares will be effected in accordance with the Exchange Agent's customary procedures with respect to securities represented by book entry.

(ii) Upon surrender of a Certificate or Book-Entry Share to the Exchange Agent for exchange, together with a duly executed letter of transmittal and such other documents as may be reasonably required by the Exchange Agent or Parent (or in the case of DTC, the customary surrender procedures of DTC and the Exchange Agent), the holder of such Shares will be entitled to receive in exchange for such properly surrendered Shares an amount in cash equal to the product (rounded to the nearest cent) of (A) the number of Shares represented by such holder's properly surrendered Certificates and Book-Entry Shares and (B) the Merger Consideration.

(c) No Further Rights in Company Common Stock. All Merger Consideration paid upon surrender of Certificates or Book-Entry Shares in accordance with the terms of this Article II will be deemed to have been paid, as the case may be, in full satisfaction of all rights pertaining to the Shares formerly represented by such Certificates or Book-Entry Shares.

(d) Adjustments. Without limiting in any way the covenants in Sections 5.1 and 5.2, if at any time during the period between the date of this Agreement and the Effective Time, any change in the outstanding shares of capital stock of the Company occurs as a result of any reclassification, recapitalization, stock split (including a reverse stock split) or combination, exchange or readjustment of shares, or any stock dividend or stock distribution with a record date during such period, the Merger Consideration will be equitably adjusted to reflect such change.

(e) Termination of Exchange Fund. Any portion of the Exchange Fund (including proceeds of any investment thereof) that remains undistributed to the holders of Shares on the date that is one year after the Effective Time will be delivered to Parent, upon demand, and any holders of Shares who have not theretofore complied with this Article II will thereafter look only to Parent for the Merger Consideration to which they are entitled pursuant to Section 1.5(a).

(f) No Liability. None of the Exchange Agent, Parent or the Surviving Corporation will be liable to any holder of Shares for any Merger Consideration from the Exchange Fund or other cash delivered to a public official pursuant to any abandoned property, escheat or similar Law. Any portion of the Exchange Fund remaining unclaimed by holders of Shares as of a date that is immediately prior to such time as such amounts would otherwise escheat to or become property of any Governmental Entity will, to the extent permitted by applicable Law, become the property of Parent free and clear of any claims or interest of any Person previously entitled thereto.

(g) Withholding Rights. Each of the Surviving Corporation, the Exchange Agent, Parent and Merger Sub will be entitled to deduct and withhold from any amounts otherwise payable pursuant to this Agreement such amount as it is required to deduct and withhold with respect to the making of such payment under the Code, the Treasury Regulations, any provision of applicable state, local or foreign Tax Law or any other Law. To the extent that amounts are so withheld, such withheld amounts will be treated for purposes of this Agreement as having been paid to the Person in respect of which such deduction and withholding was made.

(h) Lost Certificates. In the event that any Certificate will have been lost, stolen or destroyed, the Exchange Agent will issue in exchange for such lost, stolen or destroyed Certificate, upon the making of an affidavit of that fact by the holder thereof, the Merger Consideration; except that Parent may, in its reasonable discretion and as a condition precedent to the payment of such Merger Consideration, require the owner of such lost, stolen or destroyed Certificate to deliver a bond in such reasonable and customary amount as it may direct as indemnity against any claim that may be made against Parent, Merger Sub, the Surviving Corporation or the Exchange Agent with respect to the Certificate alleged to have been lost, stolen or destroyed.

Section 2.2 Stock Transfer Books. At the Effective Time, the stock transfer books of the Company will be closed and there will be no further registration of transfers of Shares thereafter on the records of the Company. On or after the Effective Time, any Certificates or Book-Entry Shares presented to the Exchange Agent or Parent for any reason will be cancelled and exchanged for the Merger Consideration with respect to the Shares formerly represented by such Certificates or Book-Entry Shares to which the holders thereof are entitled pursuant to Section 1.5(a).

Section 2.3 Company Stock Awards.

(a) Stock Options. At the Effective Time, each option award to purchase Shares granted under the Company Equity Incentive Plans (each, a "Company Stock Option") that is vested and outstanding immediately prior to the Effective Time will be cancelled, with the holder thereof becoming entitled to receive an amount in cash, payable in accordance with Section 2.3(f), equal to the product of (i) the total number of Shares subject to such Company Stock Option as of immediately prior to the Effective Time and (ii) the excess, if any, of (A) the Merger Consideration over (B) the exercise price per Share of such Company Stock Option.

(b) Company Restricted Shares. At the Effective Time, each award of restricted Shares granted under the Company Equity Incentive Plans (each, a "Company Restricted Share") that is outstanding as of immediately prior to the Effective Time will be deemed to be fully vested (without proration or other reduction in respect of the portion of the applicable vesting period elapsed) and will be cancelled, with the holder thereof becoming entitled to receive an amount in cash, payable in accordance with Section 2.3(f), equal to the product of (i) the total number of Shares subject to such award of Company Restricted Shares as of immediately prior to the Effective Time and (ii) the Merger Consideration, together with any dividends credited thereto in accordance with the terms of the applicable award agreement.

(c) Company RSUs. At the Effective Time, each award of restricted stock units payable in whole or in part in Shares, or the value of which is determined with reference to the value of Shares, and granted under the Company Equity Incentive Plans (each, a "Company RSU") that is outstanding as of immediately prior to the Effective Time will be deemed to be fully vested (without proration or other reduction in respect of the portion of the applicable vesting period elapsed) and will be cancelled, with the holder thereof becoming entitled to receive an amount in cash, payable in accordance with Section 2.3(f), equal to the product of (i) the total number of Shares subject to such award of Company RSUs as of immediately prior to the Effective Time (based on the achievement of applicable performance criteria, if any) and (ii) the Merger Consideration, together with any dividends credited thereto in accordance with the terms of the applicable award agreement.

(d) Company PSUs. At the Effective Time, each award of performance share units payable in whole or in part in Shares, or the value of which is determined with reference to the value of Shares, and granted under the Company Equity Incentive Plans (each, a "Company PSU") that is outstanding as of immediately prior to the Effective Time will be assumed by Parent and converted (without proration or other reduction in respect of the portion of the applicable performance period elapsed) into an award of restricted stock units by Parent (an "Assumed Award") with respect to a number of shares of common stock of Parent, par value $5 per share ("Parent Common Stock"), equal to the product of (i) the greater of (A) 125% of the number of units underlying such Company PSU based on target level of achievement of all relevant performance goals and (B) the number of units underlying such Company PSU based on the actual level of achievement of all relevant performance goals against target as of immediately prior to the Effective Time (as adjusted to the extent equitably required), as determined by the Company Board (or, if appropriate, any committee thereof) prior to the Effective Time, multiplied by (ii) the Exchange Ratio (rounded to the nearest whole share), on the same terms and conditions relating to vesting schedule and payment terms, and otherwise on similar terms and conditions, as were applicable to such Company PSU as of immediately prior to the Effective Time, except (1) as otherwise described in this Section 2.3 or in Section 2.3(d) of the Company Disclosure Letter and (2) that such Assumed Award will not be subject to any performance goals and the vesting of such Assumed Award will be based solely on the continued service of the holder thereof. If a participant dies or becomes Disabled (with such term as defined in the Company's Omnibus Performance Incentive Plan) or, if within two years after the

Effective Time, a participant's employment is terminated without "Cause" or the participant resigns for "Good Reason" (with such terms as defined in the Company Omnibus Performance Incentive Plan or, as applicable, a continuity agreement between the participant and the Company), then all time-based vesting restrictions on such participant's outstanding Assumed Awards will lapse on a prorated basis based on the length of time during the vesting period (measured from the vesting commencement date of the corresponding Company PSU) that has elapsed prior to such participant's date of termination of employment. For purposes of this Section 2.3, "Exchange Ratio" means a fraction, the numerator of which is the Merger Consideration and the denominator of which is the volume-weighted average price per share of Parent Common Stock on the NYSE (as reported by Bloomberg L.P. or, if not reported therein, in another authoritative source mutually selected by Parent and the Company) on each of the five consecutive trading days ending on (and inclusive of) the trading day that is two trading days immediately prior to the Closing Date.

(e) Deferred Stock Units. At the Effective Time, each award of Company Deferred Stock Units that is outstanding as of immediately prior to the Effective Time will be cancelled, with the holder thereof becoming entitled to receive an amount in cash, payable in accordance with Section 2.3(f), equal to the product of (i) the total number of Shares subject to such award of Company Deferred Stock Units as of immediately prior to the Effective Time and (ii) the Merger Consideration, together with any dividends credited thereto in accordance with the terms of the applicable Company Deferred Compensation Plan.

(f) Payment. As soon as reasonably practicable (but in no event later than two Business Days) following the Effective Time, the Surviving Corporation will pay the amounts due to the holders of Company Stock Options pursuant to Section 2.3(a), the amounts due to the holders of Company Restricted Shares pursuant to Section 2.3(b) and the amounts due to the holders of Company RSUs pursuant to Section 2.3(c), in each case without interest and subject to any required Tax withholding. The Surviving Corporation will pay the amounts due to the holders of Company Deferred Stock Units pursuant to Section 2.3(e) in accordance with the terms of the applicable Company Deferred Compensation Plan. Following the Effective Time, the Surviving Corporation will pay any amounts due in respect of all Assumed Awards pursuant to the terms of such Assumed Awards. To the extent any amounts described in this Section 2.3(f) relate to a Company Stock Award that is nonqualified deferred compensation subject to Section 409A of the Code, the Surviving Corporation will pay such amounts at the earliest time permitted under the terms of the applicable agreement, plan or arrangement relating to such Company Stock Award that will not trigger a tax or penalty under Section 409A of the Code.

(g) Notice. Prior to the Effective Time, the Company will be permitted (but not obligated) to send a written notice in a form reasonably acceptable to Parent to each holder of an outstanding Company Stock Option, Company Restricted Share, Company RSU, Company PSU and Company Deferred Stock Unit (the "Company Stock Awards") that will inform such holder of the treatment of such awards as provided in this Section 2.3, and otherwise setting forth such holder's rights pursuant to the applicable Company Equity Incentive Plan, Company Deferred Compensation Plan and equity award agreements.

(h) Further Assurances. The Company will, prior to the Effective Time, take (or cause to be taken) any and all actions as may be necessary (including obtaining any resolutions of the Company Board and, to the extent required, any committee thereof) to implement the foregoing provisions of this Section 2.3. In addition, Parent may reasonably request, after consultation with the Company, that the Company obtain consents from certain holders of Company PSUs prior to the Effective Time with respect to the treatment of such holders' Company PSUs pursuant to Section 2.3(d). If the Company is not able to obtain any such consent prior to the Effective Time, then, notwithstanding the terms of Section 2.3(d), Parent may elect to not assume the Company PSUs held by such holder, in which case such Company PSUs will be treated as set forth under the Company Omnibus Performance Incentive Plan for awards not assumed or substituted by the surviving entity, and Parent will notify the Company of such election as soon as practicable.

(i) No Further Rights. Other than with respect to Assumed Awards relating to Parent Common Stock, following the Effective Time, no holder of a Company Stock Award, participant in any Company Equity Incentive Plan or other Company Benefit Plan or employee benefit arrangement of the Company or party to any employment agreement with the Company will have any right hereunder to acquire any capital stock or other Equity Interests (including any "phantom" stock or stock appreciation rights) in the Company, any of its Subsidiaries or the Surviving Corporation.

Section 2.4 Treatment of Employee Stock Purchase Plan. Except as otherwise provided in this Section 2.4, each current "Offering Period" (as defined in the Company ESPP) (an "Offering Period") in progress as of the date of this Agreement under the Company ESPP will continue, and the Shares will be issued to participants thereunder on the next currently scheduled purchase dates thereunder occurring after the date of this Agreement as provided under, and subject to the terms and conditions of, the Company ESPP. New Offering Periods under the Company ESPP will be permitted to commence following the date of this Agreement in the ordinary course of business. Any Offering Period in progress as of the Effective Time will be shortened, and the last day of each such Offering Period will be the tenth Business Day immediately preceding the Effective Time. Each then outstanding ESPP Purchase Right will be exercised automatically on the last day of such Offering Period. Notwithstanding any restrictions on transfer of stock in the Company ESPP, the treatment in the Merger of any Shares under this provision will be in accordance with Section 2.1(a). The Company will terminate the Company ESPP as of or prior to the Effective Time. The Company will, promptly after the date of this Agreement, take all actions (including, if appropriate, amending the terms of the Company ESPP) that are necessary to give effect to the transactions contemplated by this Section 2.4.

Section 2.5 Appraisal Rights. Notwithstanding anything in this Agreement to the contrary, any Shares that are issued and outstanding immediately prior to the Effective

Time and are held by a shareholder who is entitled to exercise, and properly exercises, dissenters' rights with respect to such Shares (each, a "Dissenting Shareholder") pursuant to, and who complies in all respects with, the provisions of the GBCC (collectively, the "Dissenting Shares") will not be converted into the right to receive the Merger Consideration at the Effective Time (except as provided in this Section 2.5). At the Effective Time, any Dissenting Shareholder will cease to have any rights to such Dissenting Shares except for the right to receive payment of the fair value of such Dissenting Shares as may be determined to be due in accordance with the GBCC, except that all Dissenting Shares held by any Dissenting Shareholder who will have failed to perfect or who otherwise will have withdrawn, in accordance with the GBCC, or lost such Dissenting Shareholder's rights to demand payment in respect of such Dissenting Shares under the GBCC, will thereupon be deemed to have been converted into the right to receive, without any interest thereon, the Merger Consideration in accordance with Article I and Article II, less applicable withholding Taxes, if any, required to be withheld. The Company will not, except with the prior written consent of Parent, voluntarily make (or cause or permit to be made on its behalf) any payment with respect to, or settle or make a binding offer to settle with, any Dissenting Shareholder regarding its exercise of dissenters' rights prior to the Effective Time. The Company will give Parent notice of any such demands prior to the Effective Time, and Parent will have the right to participate in all negotiations and proceedings with respect to any exercise by any shareholder of dissenters' rights.

ARTICLE III

REPRESENTATIONS AND WARRANTIES OF THE COMPANY

Except as disclosed in the Company Reports publicly available at least 24 hours prior to the date of this Agreement and only as and to the extent disclosed therein (other than any forward-looking disclosures set forth in any risk factor section, any disclosures in any section relating to forward-looking statements and any other disclosures included therein to the extent they are primarily cautionary, predictive or forward-looking in nature) or in the disclosure letter delivered by the Company to Parent immediately prior to the execution of this Agreement (it being agreed that any information set forth in one section of such disclosure letter will be deemed to apply to each other section thereof to which its relevance as an exception to (or disclosure for the purposes of) such other section is reasonably apparent) (the "Company Disclosure Letter"), the Company represents and warrants to Parent as follows:

Section 3.1 Corporate Organization.

(a) The Company is a corporation duly organized, validly existing and in good standing under the Laws of the State of Georgia. The Company has the corporate power and authority to own or lease all of its properties and assets and to carry on its business as it is now being conducted, and is duly licensed or qualified to do business in each jurisdiction in which the nature of the business conducted by it or the character or location of the properties and assets owned or leased by it makes such licensing or qualification necessary, except where the failure to be so licensed or qualified has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(b) The Company has made available to Parent copies of the amended and restated articles of incorporation of the Company (the "Company Charter") and the bylaws of the Company (the "Company Bylaws"), each as amended through the date hereof, and each as in effect as of the date of this Agreement.

(c) Section 3.1(c) of the Company Disclosure Letter sets forth a list of each Company Subsidiary, together with the jurisdiction of organization or incorporation, as the case may be, and the jurisdictions in which each Company Subsidiary is authorized to conduct business. Each Company Subsidiary (i) is duly organized and validly existing under the Laws of its jurisdiction of organization, (ii) is duly qualified to do business and in good standing in all jurisdictions (whether federal, state, local or foreign) where its ownership or leasing of property or the conduct of its business requires it to be so qualified, and (iii) has all the corporate or limited liability company power and authority to own or lease its properties and assets and to carry on its business as now conducted, in the case of clause (ii), except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. As used in this Agreement, the word "Subsidiary" when used with respect to any Person, means another Person: (i) any amount of the voting securities, other voting rights or voting partnership interests of which is sufficient to elect at least a majority of its board of directors or other governing body; or (ii) more than 50% of the Equity Interests of which is owned directly or indirectly by such first Person. The term "Company Subsidiary" means any direct or indirect Subsidiary of the Company, except that for the purposes of Section 3.18(k) only, "Company Subsidiary" also means any Person that is an "affiliate" of the Company as the term "affiliate" is used in 18 C.F.R. Sec. 35.36(a)(9). The term "Parent Subsidiary" means any direct or indirect Subsidiary of Parent and will include (A) Merger Sub prior to the Effective Time and (B) the Surviving Corporation as of and after the Effective Time.

(d) The Company has made available to Parent copies of the articles of incorporation of each Company Subsidiary and the bylaws of each Company Subsidiary, each as amended through the date hereof, and each as in effect as of the date of this Agreement.

Section 3.2 Capitalization.

(a) The authorized capital stock of the Company consists of (i) 750,000,000 Shares, of which, as of the close of business on August 20, 2015 (the "Measurement Date"), 120,071,870 Shares were issued and outstanding (including Company Restricted Shares), (ii) 10,000,000 shares of Company preferred stock, no par value, of which, as of the Measurement Date, no shares were issued and outstanding, and (iii) 10,000,000 shares of Company Class A junior participating preferred stock, no par value, of which, as of the Measurement Date, no shares were issued and outstanding (collectively, the "Company Capital Stock"). As of the Measurement Date, 216,523 Shares were held in the Company's treasury. As of the

Measurement Date, 3,661,996 Shares were reserved for issuance under the Company Omnibus Performance Incentive Plan, no Shares were reserved for issuance under the Company Long-Term Incentive Plan, 363,675 Shares were reserved for issuance under the Company ESPP and 2,031,307 Shares were reserved for issuance under the Company DRIP. All of the issued and outstanding Shares have been duly authorized and validly issued and are fully paid, nonassessable and free of preemptive rights.

(b) The Company has provided Parent with an accurate and complete list of each Company Stock Award outstanding as of the Measurement Date pursuant to the Company Equity Incentive Plans. All outstanding Company Stock Awards were granted under a Company Equity Incentive Plan and are evidenced by award agreements, in each case in all material respects in the forms made available by the Company to Parent, and no award agreement contains terms that are inconsistent with or in addition to such forms in any material respect. From the Measurement Date until the date of this Agreement, the Company has not issued any Shares or Company Stock Awards or other equity securities of the Company or any securities representing the right to purchase or otherwise receive any Shares (other than in connection with (i) the exercise or settlement of Company Stock Awards or ESPP Purchase Rights granted prior to the Measurement Date or (ii) the issuance of Shares under the Company DRIP).

(c) Except pursuant to this Agreement, the Company Equity Incentive Plans, the Company ESPP, the Company DRIP or as set forth in this Section 3.2, the Company does not have and is not bound by any outstanding subscriptions, options, warrants, calls, commitments or agreements of any character calling for the purchase, issuance or registration of any Shares or any other equity securities of the Company or any securities representing the right to purchase or otherwise receive any Shares.

(d) There are no bonds, debentures, notes or other indebtedness having the right to vote on any matters on which shareholders of the Company may vote that are issued or outstanding as of the date of this Agreement.

(e) All of the issued and outstanding shares of capital stock or other equity ownership interests of each Company Subsidiary that are owned by the Company, directly or indirectly, are owned free and clear of any Liens (other than transfer restrictions under applicable federal and state securities Laws), and all of such shares or equity ownership interests are duly authorized and validly issued and are fully paid, nonassessable and free of preemptive rights. No Company Subsidiary has or is bound by any outstanding subscriptions, options, warrants, calls, commitments or agreements of any character calling for the purchase or issuance of any shares of capital stock or any other equity security of such Company Subsidiary or any securities representing the right to purchase or otherwise receive any shares of capital stock or any other equity security of such Company Subsidiary. There are no outstanding obligations (other than those under applicable securities Laws) to which the Company or any Company Subsidiary is a party restricting the transfer of, or limiting the exercise of voting rights with respect to, any Equity Interest in any Company Subsidiary.

Section 3.3 Authority; No Violation.

(a) The Company has all requisite corporate power and authority to enter into this Agreement and, subject to receipt of the Company Shareholder Approval and the Regulatory Approvals, to consummate the Merger and the other transactions contemplated by this Agreement (the "Transactions"). The execution and delivery of this Agreement and the consummation of the Transactions have been duly and validly adopted by the Company Board and, except for the approval of this Agreement by a majority of all the votes entitled to be cast on the Agreement by all shares of Company Capital Stock entitled to vote on the Agreement, voting as a single voting group (the "Company Shareholder Approval"), no other corporate proceedings on the part of the Company are necessary to authorize the consummation of the Transactions. Subject to Section 6.9(c), the Company Board has (i) adopted this Agreement and determined that this Agreement and the Transactions are advisable and fair to and in the best interests of the Company's shareholders and (ii) resolved to (A) submit this Agreement for approval by the Company's shareholders and (B) transmit to such shareholders a recommendation that such shareholders approve this Agreement and the Transactions. This Agreement has been duly and validly executed and delivered by the Company and, assuming this Agreement constitutes the valid and binding agreement of Parent and Merger Sub, constitutes the valid and binding agreement of the Company, enforceable against the Company in accordance with its terms, except as such enforceability (A) may be limited by bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar Laws affecting or relating to enforcement of creditors' rights generally and (B) is subject to general principles of equity (regardless of whether enforceability is considered in a proceeding at Law or in equity).

(b) None of the execution and delivery of this Agreement by the Company, the consummation of the Transactions, or compliance by the Company with any of the terms or provisions of this Agreement, will (i) violate any provision of the articles of incorporation or bylaws or other equivalent organizational document, in each case, as amended, of the Company or any of the Company Subsidiaries or (ii) assuming that the consents, approvals and filings referred to in Section 3.4 are duly obtained or made, (A) violate any Order or any Law applicable to the Company, any of the Company Subsidiaries or any of their respective properties or assets or (B) violate, conflict with, or result in a breach of any provision of or constitute a default (with or without notice or lapse of time, or both) under, result in the termination of or give rise to a right of termination or cancellation under, accelerate the performance required by, or result in the creation of any Lien (other than a Permitted Lien) upon any of the respective properties or assets of the Company or any of the Company Subsidiaries under, any of the terms, conditions or provisions of any credit agreement, note, bond, mortgage, indenture, deed of trust, license, lease or other instrument or obligation to which the Company or any Company Subsidiary is a party, or by which they or any of their respective properties or assets may be bound or affected, except for such violations, conflicts, breaches or defaults referred to in clause (ii) that would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

Section 3.4 Consents and Approvals. Except for (a) the filing with the SEC of a proxy statement in definitive form relating to the Company Shareholders Meeting (the "Proxy Statement") pursuant to the Securities Exchange Act of 1934, as amended, and the rules and regulations promulgated thereunder (the "Exchange Act"), (b) the filing of the Certificate of Merger by the Secretary of State of the State of Georgia pursuant to the GBCC, (c) any notices or filings under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act"), (d) filings required by the applicable requirements of the Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder (the "Securities Act") or the Exchange Act in connection with this Agreement and the Transactions, (e) filings and approvals as may be required under the rules and regulations of NYSE in connection with this Agreement and the Transactions, (f) any notices, filings or approvals with the California Public Utilities Commission, Georgia Public Service Commission, Illinois Commerce Commission, Maryland Public Service Commission, New Jersey Board of Public Utilities, Tennessee Regulatory Authority and Virginia State Corporation Commission (the "State Commissions") and under applicable state Laws (the "State Approvals"), (g) the approval of the Federal Communications Commission ("FCC") for the transfer of control over the FCC licenses of the entities listed in Section 3.4 of the Company Disclosure Letter ("FCC Approval") and (h) the consents or approvals listed in Section 3.4 of the Company Disclosure Letter, no consents or approvals of or filings or registrations with any United States or foreign court, administrative agency or commission or other governmental authority or instrumentality (each a "Governmental Entity") are necessary in connection with (i) the execution and delivery by the Company of this Agreement and (ii) the consummation by the Company of the Transactions, except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

Section 3.5 Reports.

(a) The Company and each of the Company Subsidiaries has filed with or furnished to the SEC, on a timely basis, all registration statements, reports, forms, documents and proxy statements required to be filed or furnished pursuant to the Securities Act or the Exchange Act, as applicable, since December 31, 2012 (collectively, and in each case including all exhibits and schedules thereto and documents incorporated by reference therein, as such statements and reports may have been amended since the date of their filing, the "Company Reports"). As of their respective effective dates (in the case of Company Reports that are registration statements filed pursuant to the requirements of the Securities Act) and as of their respective filing or furnished dates, as applicable (in the case of all other Company Reports), or in the case of amendments thereto, as of the most recent such amendment, the Company Reports complied in all material respects with the requirements of the Securities Act, the Exchange Act and the Sarbanes-Oxley Act of 2002 (including the rules and regulations promulgated thereunder, "SOX"), as the case may be, and the rules and regulations of the SEC thereunder, applicable to such Company Reports, and none of the Company Reports as of such respective dates (or, if amended, the date of the filing or furnishing, as applicable, of such amendment, with respect to the disclosures that are amended) contained any untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary to make the statements therein, in light of the circumstances under which they were made, not misleading.

(b) Each of the principal executive officer of the Company and the principal financial officer of the Company (or each former principal executive officer of the Company and each former principal financial officer of the Company, as applicable) has made all applicable certifications required by Rule 13a-14 or 15d-14 under the Exchange Act and Sections 302 and 906 of SOX with respect to the Company Reports and the statements contained in such certifications are complete and accurate. For purposes of this Agreement, "principal executive officer" and "principal financial officer" have the meanings ascribed to such terms in SOX. Neither the Company nor any of the Company Subsidiaries has outstanding, or has since December 31, 2012 arranged any outstanding, "extensions of credit" to or for directors or executive officers of the Company in violation of Section 402 of SOX.

(c) The Company maintains a system of "internal control over financial reporting" (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) sufficient to provide reasonable assurance (i) that transactions are recorded as necessary to permit preparation of financial statements in conformity with GAAP, consistently applied, (ii) that transactions are executed only in accordance with the authorizations of management and directors and (iii) regarding prevention or timely detection of the unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

(d) The "disclosure controls and procedures" (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) utilized by the Company are reasonably designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that all such information required to be disclosed is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure and to enable the principal executive officer and principal financial officer of the Company to make the certifications required under the Exchange Act with respect to such reports.

(e) Based on its most recent evaluation of internal controls prior to the date hereof, the Company has disclosed to the Company's auditors and the audit committee of the Company Board (i) any and all "significant deficiencies" and "material weaknesses" in the design or operation of internal controls over financial reporting that are reasonably likely to adversely affect in any material respect the Company's ability to report financial information and (ii) any fraud, whether or not material, that involves management or other Employees who have a significant role in the Company's internal controls over financial reporting, and any such deficiency, weakness and fraud so disclosed to auditors, if any, has been disclosed to Parent prior to the date hereof.

(f) None of the Company Subsidiaries is, or at any time since December 31, 2012 has been, subject to the reporting requirements of Sections 13(a) or 15(d) of the Exchange Act.

Section 3.6 Financial Statements.

(a) The consolidated financial statements of the Company and the Company Subsidiaries (including in each case, any related notes and schedules thereto, where applicable) included in the Company Reports (collectively, the "Company Financial Statements"), fairly present in all material respects the consolidated financial position of the Company and the Company Subsidiaries as of the date thereof, and fairly present in all material respects the results of the consolidated operations, changes in shareholders' equity, cash flows and consolidated financial position of the Company and the Company Subsidiaries for the respective fiscal periods or as of the date therein set forth, except the Company Financial Statements are subject, in the case of unaudited statements, to normal year-end audit adjustments. Each of the Company Financial Statements (including the related notes and schedules thereto, where applicable), as of their respective dates, complied in all material respects with applicable accounting requirements and with the published rules and regulations of the SEC with respect thereto and each of such statements (including the related notes and schedules thereto, where applicable) and have been prepared, in all material respects, in accordance with GAAP consistently applied during the periods involved, except as indicated in such statements or in the notes thereto.

(b) Except for those liabilities that are reflected or reserved against on the June 30, 2015 consolidated balance sheet of the Company and the Company Subsidiaries included in the Company Financial Statements and for liabilities incurred in the ordinary course of business consistent with past practice since June 30, 2015, neither the Company nor any of the Company Subsidiaries has incurred any liability of any nature whatsoever (whether absolute, accrued, contingent or otherwise and whether due or to become due and including any off-balance sheet financings, loans, indebtedness, make whole or similar liabilities or obligations) that would be required under GAAP to be reflected in a consolidated balance sheet of the Company and the Company Subsidiaries, except for liabilities and obligations that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

Section 3.7 Absence of Company Material Adverse Effect. Since June 30, 2015, no changes, events or developments have occurred that have had or would reasonably be expected to have, individually or in the aggregate, with all such other changes, events or developments, a Company Material Adverse Effect.

Section 3.8 Legal Proceedings.

(a) As of the date hereof, there are no (i) legal, administrative, arbitral or other proceedings, claims, actions or suits (each, an "Action") to which the Company or any of the Company Subsidiaries is a party pending or, to the knowledge of the

Company, threatened, or (ii) investigations, to the knowledge of the Company, involving the Company or any of the Company Subsidiaries, in each case that has had or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(b) There is no Order imposed upon the Company, any of the Company Subsidiaries or the assets of the Company or any of the Company Subsidiaries that has had, individually or in the aggregate, a Company Material Adverse Effect.

Section 3.9 Taxes and Tax Returns.

(a) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, each of the Company and the Company Subsidiaries has duly filed all federal, state, foreign and local Tax Returns required to be filed by any of them, taking into account any extensions of time within which to file (all such returns being accurate and complete) and has duly paid or made provision for the payment of all Taxes that have been incurred or are due or claimed to be due from them by federal, state, foreign or local taxing authorities (other than Taxes that are not yet delinquent or that are being contested in good faith, have not been finally determined and have been adequately reserved against).

(b) Any material liability with respect to deficiencies asserted as a result of any audit, examination or similar proceeding of the Company or any Company Subsidiary Tax Return by the IRS or any other taxing authority is covered by adequate reserves in accordance with GAAP in the Company Financial Statements. There are no disputes pending, or claims asserted in writing, for material Taxes or assessments upon the Company or any of the Company Subsidiaries for which the Company does not have adequate reserves.

(c) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, neither the Company nor any of the Company Subsidiaries is a party to or is bound by any Tax sharing, allocation or indemnification agreement or arrangement (other than such an agreement or arrangement (i) exclusively between or among the Company and the Company Subsidiaries or (ii) the primary purpose of which is not the allocation or payment of Taxes).

(d) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, neither the Company nor any of the Company Subsidiaries has agreed to or granted any extension or waiver of the limitation period applicable to any Taxes or Tax Returns, which extension or waiver is currently in effect (other than pursuant to extensions of time to file Tax Returns obtained in the ordinary course of business).

(e) Within the past six years, neither the Company nor any of the Company Subsidiaries has distributed the stock of any corporation, or had its stock distributed, in a transaction intended to satisfy the requirements of Section 355 of the Code.

(f) Each of the Company and the Company Subsidiaries has properly and timely withheld or collected and timely paid over to the appropriate taxing authority (or each is properly holding for such timely payment) all material amounts of Taxes required to be withheld, collected and paid over by applicable Law.

(g) There are no material Liens for Taxes upon any asset of the Company or any Company Subsidiary other than Permitted Liens (within the meaning of clause (c) of such term).

(h) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, neither the Company nor any of the Company Subsidiaries is a party to or bound by any advance pricing agreement, closing agreement or other similar agreement or ruling relating to Taxes.

(i) Neither the Company nor any of the Company Subsidiaries has engaged in a transaction that constitutes a "listed transaction" for purposes of Section 6011 of the Code and the applicable Treasury Regulations thereunder.

(j) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, no written claim has been made in the past three years by a taxing authority in a jurisdiction where the Company or any Company Subsidiary does not file Tax Returns that any of them is or may be subject to Tax by that jurisdiction.

(k) The Company and the Company Subsidiaries have complied with the normalization rules described in Section 168(i)(9) of the Code and any other applicable provisions of the Code or Treasury Regulations with respect to any public utility property (as defined in Section 168(i)(10) of the Code).

Section 3.10 Employee Benefit Plans; Labor.

(a) Section 3.10(a) of the Company Disclosure Letter sets forth, as of the date hereof, a true and complete list of the material (i) nonqualified deferred compensation or retirement plans for Employees located in the United States, (ii) qualified "defined contribution plans" (as such term is defined under Section 3(34) of ERISA), (iii) qualified "defined benefit plans" (as such term is defined under Section 3(35) of ERISA) (the plans set forth in clauses (ii) and (iii) are collectively referred to herein as the "Pension Plans"), (iv) "welfare benefit plans" (as such term is defined under Section 3(1) of ERISA) (the "Welfare Plans"), and (v) compensatory fringe benefit or stock option plans, including written individual contracts, employee agreements, plans, programs, or arrangements, whether funded or unfunded, that, as of the date hereof, are, or within the past five fiscal years of the Company or any Company Subsidiary, as applicable, have been, maintained and sponsored in whole or in part, or contributed to by any of the Company, the Company Subsidiaries and the Company Commonly Controlled Entities, for the benefit of, providing any remuneration or benefits to, or covering any Employee, any dependent, spouse or other family member or beneficiary of such Employee, or any director, independent contractor, member, officer, or consultant of any of the Company, the Company Subsidiaries and the Company Commonly Controlled Entities, or under (or in connection with) which the Company or any Company Subsidiary may have any liability (collectively clauses (i) through (v) are referred to as "Company Benefit Plans").

(b) Except as has not resulted in, and would not reasonably be expected to result in, individually or in the aggregate, material liability to the Company and the Company Subsidiaries, taken as a whole, (i) each Pension Plan that is intended to meet the requirements of a "qualified plan" under Sections 401(a) and 501(a) of the Code has either received a favorable determination letter from the IRS that such Pension Plan is so qualified or has requested such a favorable determination letter within the remedial amendment period of Section 401(b) of the Code, (ii) each Company Benefit Plan, including any amendment thereto, that is eligible for approval by, and/or registration for and/or qualification for special Tax status with, the appropriate taxation, social security and/or supervisory authorities in the relevant country, state, territory or the like (each, an "Approval") has received such Approval, or there remains a period of time in which to obtain such Approval retroactive to the date of any amendment or change in Law that has not previously received such Approval, and (iii) the Company Benefit Plans comply in form and in operation in all material respects with the requirements of the Code, ERISA, PPACA and all other applicable Laws, and none of the Company, the Company Subsidiaries and its Company Commonly Controlled Entities has received any notice from any Governmental Entity questioning or challenging such compliance that has not been resolved. The Company ESPP is intended to qualify as an "employee stock purchase plan" within the meaning of Section 423 of the Code.

(c) To the knowledge of the Company, there have been no "prohibited transactions" (as that term is defined in Section 406 of ERISA or Section 4975 of the Code) with respect to any Company Benefit Plan.

(d) Except as has not resulted in, and would not reasonably be expected to result in, individually or in the aggregate, material liability to the Company and the Company Subsidiaries, taken as a whole, neither the Company nor any other Person that, together with the Company or any Company Subsidiary, is treated as a single employer under Section 414(b), (c), (m) or (o) of the Code or any other applicable Law (a "Company Commonly Controlled Entity") (i) has sponsored, maintained or contributed to, or been obligated to maintain or contribute to, or has any liability under, any Pension Plan that is subject to Title IV of ERISA or Section 412 of the Code or is otherwise a defined benefit pension plan, (ii) has any unsatisfied liability imposed under Title IV of ERISA or Section 412 of the Code or (iii) has a Pension Plan with an "accumulated funding deficiency" (as defined in Section 302 of ERISA or Section 412 of the Code), whether or not waived, nor has any waiver of the minimum funding standards of Section 302 of ERISA or Section 412 of the Code been requested for such a Pension Plan. Except as has not resulted in, and would not reasonably be expected to result in, individually or in the aggregate, material liability to the Company and the

Company Subsidiaries, taken as a whole, (A) all contributions (including all employer contributions and employee salary reduction contributions) or insurance premiums that are due have been paid with respect to each Company Benefit Plan, and all contributions or insurance premiums for any period ending on or before the Closing Date that are not yet due have been paid with respect to each such Company Benefit Plan or accrued, in each case in accordance with the past custom and practice of the Company, and with applicable Law and guidance, (B) no Pension Plan or related trust has been terminated during the last five years and (C) there has been no "reportable event" (as defined in Section 4043 of ERISA), other than an event for which the 30-day notice period has been waived, with respect to any Pension Plan during the last five years.

(e) (i) None of the Company, the Company Subsidiaries and the Company Commonly Controlled Entities contributes to or has any liability or potential liability with respect to any "multiemployer plan" (as defined in Section 3(37) of ERISA) during the five-year period ending as of the Closing Date, (ii) none of the Company, the Company Subsidiaries and the Company Commonly Controlled Entities is subject to any withdrawal or partial withdrawal liability within the contemplation of Section 4201 of ERISA and (iii) none of the Company, the Company Subsidiaries and the Company Commonly Controlled Entities has entered into any transaction which has or could subject the Company, any Company Subsidiary or any Company Commonly Controlled Entity to any such withdrawal or partial withdrawal liability.

(f) None of the Welfare Plans obligates the Company or any Company Subsidiary to provide any Employee (or any dependent thereof) any life insurance or medical or health benefits after his or her termination of employment with the Company or any Company Subsidiary, other than as required under COBRA or any similar state Law.

(g) The consummation of the Transactions will not (i) entitle any Employee (or spouse, dependent or other family member of such Employee) of the Company or Company Subsidiaries to severance pay, unemployment compensation, or any payment contingent upon a change in control or ownership of the Company or Company Subsidiaries, or (ii) accelerate the time of payment or vesting, or increase the amount, of any compensation due to any such Employee (or any spouse, dependent, or other family member of such Employee). Neither the Company nor any Company Subsidiary has any obligation to provide, and no Company Benefit Plan or other arrangement provides any Person with any amount of additional compensation or gross-up if such Person is provided with amounts subject to excise or additional Taxes, interest or penalties incurred pursuant to Sections 4999 or 409A of the Code or due to the failure of any payment to be deductible under Section 280G of the Code.

(h) Section 3.10(h) of the Company Disclosure Letter lists each collective bargaining agreement to which the Company or a Company Subsidiary is a party in respect of the Employees on the date of this Agreement. No such collective bargaining agreement is, as of the date of this Agreement, being negotiated or renegotiated in any material respect by the Company or any of the Company

Subsidiaries. Except as has not resulted in, and would not reasonably be expected to result in, individually or in the aggregate, material liabilities to the Company and the Company Subsidiaries taken as a whole, (i) as of the date of this Agreement, the Company is in compliance with all Laws concerning employment rights and obligations, (ii) as of the date of this Agreement, there is no work stoppage, slow down or strike against the Company or any of the Company Subsidiaries pending or, to the knowledge of the Company, threatened which would interfere with the respective business activities of the Company or any of the Company Subsidiaries (and no work stoppages, slow downs or strikes occurred during the last five years), (iii) to the knowledge of the Company, neither the Company nor any of the Company Subsidiaries has committed during the five years prior to the date of this Agreement any unfair labor practice in connection with the operation of the respective businesses of the Company or any of the Company Subsidiaries, and (iv) as of the date of this Agreement, there is no charge or complaint pending or, to the knowledge of the Company, threatened against the Company or any of the Company Subsidiaries by the National Labor Relations Board or any comparable Governmental Entity, and in relation to any labor rules and regulations, no other competent labor authority has a charge or complaint pending or, to the knowledge of the Company, threatened in writing.

(i) Section 3.10(i) of the Company Disclosure Letter sets forth a true and complete list of each material (i) severance or employment agreement with directors, officers, Employees, or consultants of the Company or any Company Subsidiary, (ii) severance programs of the Company or any Company Subsidiary with or relating to its Employees, or (iii) plans, programs or other agreements of the Company or any Company Subsidiary with or relating to its directors, officers, Employees or consultants which contain change in control provisions.

Section 3.11 Compliance with Applicable Law.

(a) The Company and each of the Company Subsidiaries hold all licenses, franchises, permits, variances, orders, approvals, certificates, notices, authorizations, registrations and rights of or with all Governmental Entities ("Permits") necessary for the lawful conduct of their respective businesses under and pursuant to each, and have complied in all respects with, and are not in default in any respect under, any applicable Law relating to the Company or any of the Company Subsidiaries, except where the failure to hold such Permit or such noncompliance or default has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, and no Action or investigation is pending or, to the knowledge of the Company, threatened, to suspend, modify, cancel, revoke, remove or withdraw any material Permit where such suspension, modification, cancellation, revocation, removal or withdrawal would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(b) Neither the Company nor any Company Subsidiary is in conflict with, default under, or violation of, any Law applicable to the Company or any Company Subsidiary or by which any property or asset of the Company or any Company Subsidiary is bound or affected, except for any conflicts, defaults or violations that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. To the knowledge of the Company, no investigation by any Governmental Entity with respect to the Company or any Company Subsidiary is pending, nor has any Governmental Entity indicated to the Company in writing an intention to conduct any such investigation, except for such investigations, the outcomes of which if determined adversely to the Company or any Company Subsidiary, have not had and would not reasonably be excepted to have, individually or in the aggregate, a Company Material Adverse Effect.

(c) Notwithstanding any of the foregoing, this Section 3.11 will not apply to matters relating to Intellectual Property, which is the subject of Section 3.14.

Section 3.12 Environmental Matters. Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect:

(a) the Company (i) is, and at all times during the last three years has been, in compliance with all applicable Environmental Laws and (ii) has obtained or has made timely applications for or is in the process of obtaining and has maintained and is in compliance with all Environmental Authorizations required for the operation of its business as currently conducted; and such Environmental Authorizations are in full force and effect;

(b) none of the Company's assets are subject to any Lien (other than Permitted Liens) imposed by or arising under any Environmental Law, and there is no Action pending or, threatened in writing for imposition of any such material Lien;

(c) during the last three years, the Company has not received any written communication from (i) any Environmental Authority that such Governmental Entity is undertaking an investigation that may give rise to Environmental Liability to the Company or (ii) any Environmental Authority or Person alleging that the Company is in violation of any Environmental Law or Environmental Authorization or subject to Environmental Liabilities and, to the Company's knowledge as of the date hereof, there is no reasonable basis for any such investigation, violation or Environmental Liabilities;

(d) (i) the Company has not been named, identified or alleged in any written notice or claim received by the Company to be a responsible party or a potentially responsible party under CERCLA or any state Law based on, or analogous to, CERCLA and (ii) the Company does not have any Environmental Liability, in each such case, for the disposal or Release of Hazardous Substances at any site that is not owned or leased;

(e) there is no Action arising under Environmental Laws pending against the Company nor, to the knowledge of the Company, is any such Action threatened in writing, in each such case, that would reasonably be expected to give rise to an Environmental Liability;

(f) to the knowledge of the Company, the Company has not (except as permitted pursuant to any Environmental Authorization) Released any Hazardous Substances that require, as of the date hereof, reporting, investigation, cleanup, removal, or remedial or responsive action or, as of the date hereof, otherwise would reasonably be expected to give rise to an Environmental Liability under Environmental Law;

(g) except for transfer or reissuance of Environmental Authorizations necessary to operate the Company's business, the Transactions do not require the pre-Closing consent or pre-approval of any Environmental Authority under Environmental Laws or Environmental Authorizations; and

(h) the Company is not subject to any Order arising under or imposed by, or party to an agreement with any Person obligating the Company to take remedial action, or pay costs thereof, for cleanup of contamination under, any Environmental Law.

Notwithstanding any other provisions of this Agreement to the contrary, the representations and warranties made in this Section 3.12 and the representations and warranties made in Sections 3.5(a) and 3.6(a) (to the extent the Company Reports and the Company's financial statements relate to or address environmental matters) are the sole and exclusive representations and warranties made by the Company in this Agreement with respect to Hazardous Substances, Environmental Liabilities, Environmental Laws and Environmental Authorizations.

Section 3.13 Material Contracts.

(a) Except for this Agreement and except for Company Material Contracts filed as exhibits to the Company Reports prior to the date of this Agreement or, as listed in Section 3.13(a) of the Company Disclosure Letter, as of the date of this Agreement, neither the Company nor any of the Company Subsidiaries is a party to or bound by (i) any "material contract" required to be filed as an exhibit to the Company's annual report on Form 10-K pursuant to Item 601(b)(10) of Regulation S-K of the SEC or (ii) any Contract that is:

(A) a "non-compete," or similar agreement that restricts or purports to restrict, in any material respect, the geographic area in which the Company or any of the Company Subsidiaries may conduct any material line of business;

(B) a joint venture, partnership or limited liability company agreement or other similar agreement or arrangement relating to the formation, creation, operation, management or control of any joint venture, partnership or limited liability company, other than any such agreement or arrangement solely between or among the Company and one or more Company Subsidiaries;

(C) an agreement (other than a future contract, option contract or other derivative transaction) that involves future expenditures or receipts by the Company or any Company Subsidiary of more than $40,000,000 in any one year period that cannot be terminated on less than 90 days notice without material payment or penalty;

(D) an acquisition agreement that contains "earn-out" or other contingent payment obligations that could reasonably be expected to result in future payments by the Company or a Company Subsidiary in excess of $4,000,000;

(E) an agreement relating to indebtedness for borrowed money or any financial guaranty, in each case pertaining to indebtedness in excess of $40,000,000 individually (excluding (i) indebtedness incurred to fund the purchase of natural gas storage inventory in the ordinary course of business and (ii) guarantees provided in connection with the Sequent trading business in the ordinary course of business);

(F) other than leases in the way of easements or rights of way, a material lease or sublease with respect to leased real property;

(G) a future contract, option contract or other derivative transaction, in any case relating to the supply or price of natural gas that has a term of longer than 90 days and a notional value greater than $40,000,000 (excluding any such future contract, option contract or other derivative transaction entered into by the local distribution company businesses of the Company and the Company Subsidiaries for the benefit of customers);

(H) a gas transportation contract that is reasonably expected to result in future payments by the Company or any Company Subsidiary in excess of $40,000,000 in any one year period (excluding any such contract entered into by the local distribution company businesses of the Company and the Company Subsidiaries for the benefit of customers); or

(I) other than agreements described in Section 3.13(a)(ii)(G) and Section 3.13(a)(ii)(H), an agreement entered into since December 31, 2009 relating to the disposition or acquisition by the Company or any Company Subsidiary of assets or properties in excess of $40,000,000 not made in the ordinary course of business consistent with past practice.

(all contracts of the type described in this Section 3.13(a), being referred to herein as a "Company Material Contract").

(b) To the knowledge of the Company, neither the Company nor any of the Company Subsidiaries is in breach of or default under the terms of any Company

Material Contract in any material respect. To the knowledge of the Company, no other party to any Company Material Contract is in any material respect in breach of or default under the terms of any Company Material Contract. Each Company Material Contract is a valid and binding obligation of the Company or any Company Subsidiary which is a party thereto and, to the knowledge of the Company, is in full force and effect; except that (i) such enforcement may be subject to applicable bankruptcy, insolvency, reorganization, moratorium or other similar Laws, now or hereafter in effect, relating to creditors' rights generally and (ii) equitable remedies of specific performance and injunctive and other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding therefor may be brought.

Section 3.14 Intellectual Property.

(a) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, either the Company or a Company Subsidiary owns, or is licensed or otherwise possesses all rights necessary to use, all Intellectual Property used in their respective businesses as currently conducted (collectively, the "Company Intellectual Property"). Notwithstanding anything herein to the contrary, the Parties acknowledge and agree that nothing in this Section 3.14(a) will be interpreted or construed as a representation or warranty with respect to whether there has been or is any infringement of Intellectual Property, and that those matters are addressed exclusively in Section 3.14(b) and Section 3.14(c).

(b) As of the date of this Agreement, there are no pending or, to the knowledge of the Company, threatened claims in writing by any Person alleging infringement or misappropriation by the Company or any Company Subsidiary arising from their use of the Company Intellectual Property, and to the knowledge of the Company, the conduct of the businesses of the Company and Company Subsidiaries does not infringe or misappropriate any Intellectual Property.

(c) Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (i) as of the date of this Agreement, neither the Company nor any Company Subsidiary has made any claim in writing or, to the knowledge of the Company, otherwise, since December 31, 2014 of any misappropriation or infringement by any third party of its rights to or in connection with the use of any Company Intellectual Property; and (ii) to the knowledge of the Company, no Person is infringing or misappropriating any Company Intellectual Property.

(d) Since December 31, 2014, to the knowledge of the Company, the Intellectual Property owned by the Company or any Company Subsidiary has not been used or enforced or failed to be used or enforced in a manner that would reasonably be expected to result in the abandonment, cancellation or unenforceability of any such Intellectual Property, except for such conflicts, infringements, violations, interferences, claims, invalidity, abandonments, cancellations or unenforceability that could not, individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect.

Section 3.15 Title to Properties; Assets. Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company or one of the Company Subsidiaries has good and valid title to all tangible assets owned by the Company or any of the Company Subsidiaries as of the date of this Agreement, or good and valid leasehold interests in all tangible assets leased or subleased by the Company or any of the Company Subsidiaries as of the date of this Agreement, except for such as are no longer used or useful in the conduct of its businesses or as have been disposed of in the ordinary course of business consistent with past practices. Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, all such assets, other than assets in which the Company or any Company Subsidiary have a leasehold interest, are free and clear of all Liens other than Permitted Liens.

Section 3.16 Real Property. Section 3.16 of the Company Disclosure Letter sets forth a list of all real property currently owned or leased by the Company or any Company Subsidiary that would be required to be included in an Annual Report on Form 10-K if filed for the fiscal year ending as of the date of this Agreement. Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company or one of the Company Subsidiaries has good and fee simple title to all real property owned by the Company or any of the Company Subsidiaries as of the date of this Agreement (the "Company Owned Real Property") and valid leasehold estates in all real property leased or subleased (whether as tenant or subtenant) by the Company or any of the Company Subsidiaries as of the date of this Agreement (including improvements thereon, the "Company Leased Real Property"). Except as would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company or one of the Company Subsidiaries has exclusive possession of each Company Leased Real Property and Company Owned Real Property, other than any use and occupancy rights granted to third-party owners, tenants, guests, hosts or licensees pursuant to agreements with respect to such real property. There are no options, rights of first offer, rights of first refusal or contracts outstanding for the sale, exchange or transfer of any material portion of the Company Owned Real Property.

Section 3.17 Trading.

(a) The Company has established risk parameters, limits and guidelines (including position limits and limitations on working capital and value at risk) in compliance with the risk management policy approved by the Company (the "Company Trading Guidelines") to restrict the level of risk that the Company and the non-utility Company Subsidiaries are authorized to take with respect to, among other things, the net position resulting from all physical commodity transactions, exchange-trade futures and options transactions, over-the-counter transactions and derivatives thereof and similar transactions (the "Net Company Position") and monitors compliance by the Company and Company Subsidiaries with such Company Trading Guidelines. The Company has provided a copy of the Company Trading Guidelines to Parent prior to the date of this Agreement. At no time since June 30, 2015, (a) has the Net Company Position not been within the risk parameters in all material respects that are set forth in the Company Trading Guidelines, or (b) has the exposure of the Company and the Company Subsidiaries with respect to the Net Company Position resulting from all such transactions been material to the Company and the Company Subsidiaries taken as a whole. Since June 30, 2015, the Company and the Company Subsidiaries have not, in accordance with generally recognized mark to market accounting policies, experienced an aggregate net loss in its trading and related operations that would have a Company Material Adverse Effect.

(b) The Company and each Company Subsidiary has retained and maintained records, transcripts, pricing and trade data and other information required to be retained and maintained under Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and the regulations thereunder in respect of its derivatives transactions entered into prior to and after enactment of the Dodd-Frank Act, except for such non-compliance as would not be reasonably expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company and each Company Subsidiary that has elected to "end-user exception" as set forth under Section 2(h)(7) of the Commodity Exchange Act and the regulations thereunder is in compliance with the requirements necessary to elect such exception, except for such non-compliance that has not had and would not, individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect. To the Company's knowledge, since June 30, 2013, there has been no violation of the Trading Guidelines, except that have not and would not, individually or in the aggregate, reasonably be expected to have a Company Material Adverse Effect.

Section 3.18 Regulation as a Utility.

(a) The Company is a "holding company" under the Public Utility Holding Company Act of 2005 ("PUHCA"). Each of Atlanta Gas Light Company, Chattanooga Gas Company, Pivotal Utility Holdings, Inc. (d/b/a Elkton Gas, d/b/a Florida City Gas and d/b/a Elizabethtown Gas), Virginia Natural Gas, Inc. and Northern Illinois Gas Company (d/b/a Nicor Gas Company), is a "local distribution company", "intrastate gas pipeline" or a "Hinshaw pipeline" within the meaning of the Natural Gas Act (the "NGA") and a "gas utility company" under PUHCA.

(b) Atlanta Gas Light Company is regulated as a "gas company" in the State of Georgia under Title 46 of the Official Code of Georgia Annotated.

(c) Chattanooga Gas Company is regulated as a "public utility" in the State of Tennessee under Title 65 of the Tennessee Code Annotated.

(d) Pivotal Utility Holdings, Inc. (through its operating division Elkton Gas) is regulated as a "gas company" in Maryland under the Maryland Public Service Commission Law.

(e) Pivotal Utility Holdings, Inc. (through its operating division Florida City Gas) is regulated as a "public utility" in the State of Florida under Chapter 366 of the Florida Statutes.

(f) Virginia Natural Gas, Inc. is regulated as a "public service corporation" in the Commonwealth of Virginia under Title 56 of the Code of Virginia.

(g) Northern Illinois Gas Company (d/b/a Nicor Gas Company) is regulated as a "gas company" under the Illinois Public Utilities Act, the Illinois Gas Storage Act, the Illinois Gas Pipeline Safety Act and the Illinois Gas Transmission Commission.

(h) Central Valley Storage, LLC is regulated as a "gas corporation" under Section 222 of the California Public Utilities Code and as a "public utility" under Section 216 of the California Public Utilities Code. Central Valley Gas Storage, LLC is developing a natural gas storage facility that will qualify as an "intrastate pipeline," a "Hinshaw pipeline" or both within the meaning of the NGA.

(i) Pivotal Utility Holdings, Inc. (through its operating division Elizabethtown Gas) is regulated as a "public utility" in the State of New Jersey under applicable Law.

(j) Golden Triangle Storage, Inc. is regulated as a "gas utility" in the State of Texas under Section 101.003(7) of the Gas Utility Regulatory Act and Section 121.001(a) of the Cox Act in the Texas Utilities Code.

(k) Neither the Company nor any Company Subsidiary is subject to regulation: as a public utility by FERC under Section 201(e) of the Federal Power Act, 16 U.S.C. § 824(e), or except as set forth in clauses (a) through (j) of this Section 3.18, as a public utility or public service company (or similar designation) by any state in the United States having jurisdiction over them or their respective properties or assets.

(l) All filings required to be made by the Company or any Company Subsidiary since June 30, 2015 pursuant to all applicable Laws (including each pipeline safety law, as amended, that is administered by the U.S. Department of Transportation Pipeline and Hazardous Materials Administration and Title 40, Public Utilities and Carriers, of the A.R.S.), have been filed or furnished, as applicable, on a timely basis with the applicable Governmental Entity, as the case may be, including all forms, statements, reports, agreements (oral or written) and all documents, exhibits, amendments, and supplements appertaining thereto, including all rates, tariffs, franchise, service agreements and related documents and all such filings complied, as of their respective dates, with all applicable requirements of the applicable statute and the rules and regulations thereunder, except for filings the failure of which to make in compliance with all applicable requirements of the applicable statute and rules and regulations thereunder have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(m) As of the date of this Agreement, except for recoveries subject to review and refund in the ordinary course, neither the Company nor any Company Subsidiary whose rates or services are regulated by a Governmental Entity, (i) have rates which have been or are being collected subject to refund, pending final resolution of any proceeding pending before a Governmental Entity or on appeal to the courts, or (ii) is a party to any proceeding before a Governmental Entity or on appeal from Orders of a Governmental Entity, in each case which have resulted in or would reasonably be expected to result in, individually or in the aggregate, a Company Material Adverse Effect. The Company Financial Statements have adequately reserved for all material refunds.

Section 3.19 Insurance.

(a) The Company and the Company Subsidiaries maintain reasonable insurance in such amounts and against such risks as the Company believes to be customary for the industries in which it and the Company Subsidiaries operate. Neither the Company nor any of the Company Subsidiaries has received notice of any pending or threatened cancellation with respect to any material insurance policy, and each of the Company and the Company Subsidiaries is in compliance in all material respects with all conditions contained therein.

(b) Global Energy Resource Insurance Corporation, a Hawaii corporation ("GERIC"), is a duly licensed captive insurance company in the State of Hawaii. GERIC is not licensed to do insurance business in or subject to the insurance Laws of any jurisdiction other than the State of Hawaii. GERIC is not a party to any reinsurance treaty or agreement or other insurance Contract, other than (i) reinsurance treaties or agreements with its Affiliate DIST-CO or certain unaffiliated insurance companies or reinsurers and (ii) agreements or insurance Contracts with the Company and the Company Subsidiaries. GERIC has complied and currently complies with the minimum required capital and other regulatory requirements and all applicable Laws of its regulatory domicile, except for such failures to comply which have not had, and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. GERIC has timely filed all statements and reports, together with all audited financial statements, exhibits, interrogatories, actuarial opinions, affirmations, certifications, schedules or other material supporting documents in connection therewith, required to be filed by it with the applicable Governmental Entities on forms prescribed or permitted by such Governmental Entities and no deficiencies have been asserted in writing by any Governmental Entities with respect to such statements and reports that have not been remedied, except for such failures to file which have not had, and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(c) DIST-CO Insurance Company, Inc., a Risk Retention Group, a Hawaii corporation ("DIST-CO"), is a duly licensed risk retention captive insurance company in the State of Hawaii. All of the issued and outstanding shares of voting common stock of DIST-CO are owned by the Company. DIST-CO is not a party to any reinsurance treaty or agreement or other insurance Contract, other than (i) reinsurance treaties or agreements with its Affiliate GERIC and certain unrelated insurance companies or reinsurers and (ii) agreements or insurance Contracts with the Company, the Company Subsidiaries, and certain contractors working on Company projects who are insureds and owners of shares of class B non-voting common stock of DIST-CO.

DIST-CO currently complies with the minimum required capital and other regulatory requirements, and all applicable Laws of its regulatory domicile, except for such failures to comply which have not had, and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. DIST-CO has timely filed all statements and reports, together with all audited financial statements, exhibits, interrogatories, actuarial opinions, affirmations, certifications, schedules or other material supporting documents in connection therewith, required to be filed by it with the applicable Governmental Entities on forms prescribed or permitted by such Governmental Entities and no deficiencies have been asserted in writing by any Governmental Entities with respect to such statements and reports that have not been remedied, except for such failures to file which have not had, and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(d) Enterprise Risk Consultants Corporation, a Hawaii corporation and wholly-owned Company Subsidiary ("ERCC"), is a duly licensed insurance agency in the State of Hawaii. ERCC is not licensed to do insurance business in or subject to the insurance laws of any jurisdiction other than the State of Hawaii. ERCC has complied and currently complies with the regulatory requirements, and all applicable Laws of its regulatory domicile, except for such failures to comply which have not had, and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. ERCC has timely filed all statements and reports, together with all affirmations, certifications, schedules or other material supporting documents in connection therewith, required to be filed by it with the applicable Governmental Entities on forms prescribed or permitted by such Governmental Entities and no deficiencies have been asserted in writing by any Governmental Entities with respect to such statements and reports, except for such failures to file which have not had, and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

Section 3.20 Opinions. Prior to the execution of this Agreement, the Company Board has received an oral opinion of Goldman, Sachs & Co. (to be subsequently confirmed in writing) to the effect that as of the date hereof and based upon and subject to the qualifications, assumptions and limitations set forth in such written opinion, the Merger Consideration is fair to the holders of Shares (other than Parent and its Affiliates) from a financial point of view.

Section 3.21 Information Supplied. The information relating to the Company, the Company Subsidiaries and its or their respective officers and directors that is or will be provided by the Company or its Representatives for inclusion in the Proxy Statement, and in any other document filed with any other Regulatory Agency in connection with the Transactions, will not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they are made, not misleading. The Proxy Statement (except for such portions thereof that relate only to Parent or any of the Parent Subsidiaries) will comply in all material respects with the provisions of the Exchange Act and the rules and regulations thereunder.

Section 3.22 Application of Takeover Laws. The Company and the Company Board have taken all necessary action, if any, in order to render inapplicable to the Transactions any restriction on business combinations contained in any applicable Takeover Law which is or would reasonably be expected to become applicable to Parent or Merger Sub as a result of the Transactions, including the conversion of Company Common Stock pursuant to Section 1.5.

Section 3.23 Affiliate Transactions. To the knowledge of the Company, there are not, as of the date hereof, any transactions, agreements, arrangements or understandings between the Company or the Company Subsidiaries, on the one hand, and the Company's Affiliates (other than wholly-owned Subsidiaries of the Company) or other Persons on the other hand, that would be required to be disclosed under Item 404 of Regulation S-K under the Securities Act.

Section 3.24 Shareholder Approval. The Company Shareholder Approval is the only vote of the holders of any class or series of Company Capital Stock necessary to approve this Agreement and the Transactions (including the Merger).

Section 3.25 Broker's Fees. None of the Company, any Company Subsidiary or any of their respective officers or directors has employed any broker or finder or incurred any liability for any broker's fees, commissions or finder's fees in connection with the Transactions, other than Goldman, Sachs & Co. The Company has heretofore made available to Parent a correct and complete copy of the Company's engagement letters with Goldman, Sachs & Co., which letters describe all fees payable to Goldman, Sachs & Co., in connection with the Transactions and all Contracts under which any such fees or any expenses are payable and all indemnification and other Contracts with Goldman, Sachs & Co., entered into in connection with the Transactions.

Section 3.26 No Other Representations or Warranties. Except for the representations and warranties expressly made by the Company in this Article III, neither the Company nor any other Person makes any representation or warranty with respect to the Company or the Company Subsidiaries or their respective business, operations, assets, liabilities, condition (financial or otherwise) or prospects, notwithstanding the delivery or disclosure to Parent or any of its Affiliates or Representatives of any documentation, forecasts or other information with respect to any one or more of the foregoing. The Company acknowledges that in entering into this Agreement, it relied solely upon its independent investigation and analysis and the representations and warranties of Parent and Merger Sub set forth in Article IV and that neither Parent nor Merger Sub makes any representation or warranty as to any matter whatsoever except as expressly set forth in this Agreement or in any certificate delivered by Parent or Merger Sub to the Company in accordance with the terms hereof. Absent fraud, Parent, Merger Sub, and their respective Affiliates, shareholders and members, and the Parent's Representatives will have no liability or responsibility based upon any information provided or made available or statements made or omissions therefrom to Company, the Company Subsidiaries or their respective Representatives, except as and only to the extent expressly set forth in this Agreement (as qualified by the Parent Disclosure Letter).

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF PARENT AND MERGER SUB

Except as disclosed in the Parent Reports publicly available at least 24 hours prior to the date of this Agreement and only as and to the extent disclosed therein (other than any forward-looking disclosures set forth in any risk factor section, any disclosures in any section relating to forward-looking statements and any other disclosures included therein to the extent they are primarily cautionary, predictive or forward-looking in nature) or in the disclosure letter delivered by Parent to the Company immediately prior to the execution of this Agreement (it being agreed that any information set forth in one section of such disclosure letter will be deemed to apply to each other section thereof to which its relevance as an exception to (or disclosure for the purposes of) such other section is reasonably apparent) (the "Parent Disclosure Letter"), Parent and Merger Sub represent and warrant to the Company as follows:

Section 4.1 Corporate Organization. Parent is a corporation duly organized, validly existing and in good standing under the Laws of the State of Delaware. Parent has the corporate power and authority to own or lease all of its properties and assets and to carry on its business as it is now being conducted, and is duly licensed or qualified to do business in each jurisdiction in which the nature of the business conducted by it or the character or location of the properties and assets owned or leased by it makes such licensing or qualification necessary, except where the failure to be so licensed or qualified would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

Section 4.2 Capitalization. As of the date of this Agreement, the authorized capital stock of Merger Sub consists of 100 shares of common stock, par value $0.01 per share, all of which are validly issued and outstanding. All of the issued and outstanding capital stock of Merger Sub is, and at the Effective Time will be, owned by Parent or a direct or indirect wholly-owned Subsidiary of Parent. Merger Sub has outstanding no option, warrant, right, or any other agreement pursuant to which any Person other than Parent may acquire any equity security of Merger Sub. Merger Sub has not conducted any business prior to the date hereof and has, and prior to the Effective Time will have, no assets, liabilities or obligations of any nature other than those incident to its formation and pursuant to this Agreement and the Transactions.

Section 4.3 Authority; No Violation.

(a) Each of Parent and Merger Sub has all requisite corporate power and authority to enter into this Agreement and to consummate the Transactions. The execution and delivery of this Agreement and the consummation of the Transactions have been duly and validly authorized by the Parent Board and board of directors of Merger Sub, and, except for the approval of this Agreement by Parent or a Parent Subsidiary, as the sole shareholder of Merger Sub, no other corporate proceedings on the part of Parent or Merger Sub are necessary to authorize the consummation of the Transactions. This Agreement has been duly and validly executed and delivered by

Parent and Merger Sub and, assuming this Agreement constitutes the valid and binding agreement of the Company, this Agreement constitutes the valid and binding agreement of Parent and Merger Sub, enforceable against Parent and Merger Sub in accordance with its terms, except as such enforceability (i) may be limited by bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar Laws affecting or relating to enforcement of creditors' rights generally and (ii) is subject to general principles of equity (regardless of whether enforceability is considered in a proceeding at Law or in equity).

(b) None of the execution and delivery of this Agreement by Parent or Merger Sub, the consummation of the Transactions, or compliance by Parent or Merger Sub, as applicable, with any of the terms or provisions of this Agreement, will (i) violate any provision of the certificate of incorporation of Parent, as amended and restated, the bylaws of Parent, as amended and restated, the articles of incorporation of Merger Sub or the Merger Sub Bylaws or (ii) assuming that the consents, approvals and filings referred to in Section 4.4 are duly obtained or made, (A) violate any Order or Law applicable to Parent, Merger Sub, any of the Parent Subsidiaries or any of their respective properties or assets or (B) violate, conflict with, or result in a breach of any provision of or constitute a default (with or without notice or lapse of time, or both) under, result in the termination of or give rise to a right of termination or cancellation under, accelerate the performance required by, or result in the creation of any Lien (other than a Permitted Lien) upon any of the respective properties or assets of Parent, Merger Sub or any of the Parent Subsidiaries under, any of the terms, conditions or provisions of any credit agreement, note, bond, mortgage, indenture, deed of trust, license, lease or other instrument or obligation to which Parent or any Parent Subsidiary is a party, or by which they or any of their respective properties or assets may be bound or affected, except for such violations, conflicts, breaches or defaults referred to in clause (ii) that would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

Section 4.4 Consents and Approvals. Except for (i) the filing with the SEC of the Proxy Statement, (ii) the filing of the Certificate of Merger by the Secretary of State of the State of Georgia pursuant to the GBCC, (iii) any notices or filings under the HSR Act or with any foreign antitrust or competition Governmental Entity, (iv) filings required by the applicable requirements of the Securities Act or Exchange Act, (v) filings and approvals as may be required under the rules and regulations of NYSE in connection with this Agreement and the Transactions; (vi) the State Approvals, (vi) the FCC Approval and (vii) the consents or approvals listed in Section 4.4 of the Parent Disclosure Letter, no consents or approvals of or filings or registrations with any Governmental Entity are necessary in connection with (A) the execution and delivery by Parent or Merger Sub of this Agreement and (B) the consummation by Parent and Merger Sub, as applicable, of the Transactions except as would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

Section 4.5 Legal Proceedings.

(a) Neither Parent nor any of the Parent Subsidiaries (i) is a party to any, and there are no pending or, to the knowledge of Parent, threatened, Actions against Parent or any Parent Subsidiary or (ii) is involved in any investigations involving Parent or any Parent Subsidiary except as would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(b) There is no Order imposed upon Parent, any of the Parent Subsidiaries or the assets of Parent or any Parent Subsidiary that would reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

Section 4.6 Financing. Parent has delivered to the Company true, correct and complete copies of executed Debt Commitment Letters (with only the fee, certain other economic provisions and certain other confidential terms (none of which would reasonably be expected to adversely affect the conditionality, enforceability, termination, principal amount or availability of the Financing) redacted) from each Financing Source. Assuming the Financing is funded in accordance with the Debt Commitment Letters, the aggregate net proceeds contemplated by the Debt Commitment Letters, together with cash on hand, will provide Parent and Merger Sub with cash proceeds on the Closing Date sufficient for the satisfaction of all of Parent's and Merger Sub's payment obligations under this Agreement and under the Debt Commitment Letters (including the payment of the aggregate Merger Consideration and any fees and expenses of or payable by Parent, Merger Sub or the Surviving Corporation in connection with the Merger and the Financing). Parent and Merger Sub acknowledge and agree that their obligations hereunder, including their obligations to consummate the Merger, are not subject to, or conditioned on, receipt of financing.

Section 4.7 Share Ownership. To the knowledge of Parent, as of the date of this Agreement, none of Parent, Merger Sub or any subsidiary of Parent owns (directly or indirectly, beneficially or of record) any shares of capital stock of the Company.

Section 4.8 Broker's Fees. None of Parent, any Parent Subsidiary or any of their respective officers or directors has employed any broker or finder or incurred any liability for any broker's fees, commissions or finder's fees in connection with the Merger, other than Citigroup Global Markets Inc.

Section 4.9 Vote Required. No vote of the holders of any class or series of Parent capital stock or indebtedness is necessary to approve the Transactions.

Section 4.10 No Other Representations and Warranties. Except for the representations and warranties expressly made by Parent and Merger Sub in this Article IV, neither Parent nor any other Person makes any representation or warranty with respect to Parent or the Parent Subsidiaries or their respective business, operations, assets, liabilities, condition (financial or otherwise) or prospects, notwithstanding the delivery or disclosure to the Company or any of its Affiliates or Representatives of any documentation, forecasts or other information with respect to any one or more of the foregoing. Parent and Merger Sub acknowledge that in entering into this Agreement, each relied solely upon its independent investigation and analysis and the representations and warranties of the Company and the Company Subsidiaries set forth in Article III and that the Company makes no representation or warranty as to any matter whatsoever except as expressly set forth in this Agreement or in any certificate delivered by the Company to Parent or Merger Sub in accordance with the terms hereof, and specifically (but without limiting the generality of the foregoing) that the Company makes no representation or warranty with respect to (a) any projections, estimates or budgets delivered or made available to Parent or Merger Sub (or any of their respective Affiliates, officers, directors, employees or Representatives) of future revenues, results of operations (or any component thereof), cash flows or financial condition (or any component thereof) of the Company and its Subsidiaries or (b) the future business and operations of the Company and its Subsidiaries. Absent fraud, the Company, the Company Subsidiaries, and their respective Affiliates, shareholders, members, and Representatives will have no liability or responsibility based upon any information provided or made available or statements made or omissions therefrom to Parent, the Parent Subsidiaries or their respective Representatives, except as and only to the extent expressly set forth in this Agreement (as qualified by the Company Disclosure Letter).

ARTICLE V

PRE-CLOSING COVENANTS

Section 5.1 Conduct of Businesses by the Company Prior to the Effective Time. During the period from the date of this Agreement to the earlier of the termination of this Agreement in accordance with its terms and the Effective Time (except as contemplated or permitted by this Agreement, a provision of the Company Disclosure Letter, as required by a Governmental Entity or applicable Law or as Parent may otherwise consent in writing (which consent will not be unreasonably withheld, conditioned or delayed)), the Company will, and will cause each of the Company Subsidiaries to, (a) use commercially reasonable efforts to conduct, in all material respects, its business in the ordinary course and (b) use commercially reasonable efforts to preserve intact its business organization and its significant business relationships.

Section 5.2 Company Forbearances. Without limiting the generality of Section 5.1, during the period from the date of this Agreement to the earlier of the termination of this Agreement in accordance with its terms and the Effective Time (except as contemplated or permitted by this Agreement, a provision of the Company Disclosure Letter or as required by applicable Law), the Company will not, and will not permit any of the Company Subsidiaries to, without the prior written consent of Parent (which consent will not be unreasonably withheld, conditioned or delayed):

(a) incur any indebtedness for borrowed money, assume or guarantee the obligations of any other individual, corporation or other entity, other than a wholly-owned Company Subsidiary (but not including accrual of interest on or maturity of obligations incurred before the date of this Agreement), in excess of $800,000,000 in the aggregate, or make any loan or advance to any other individual, corporation or other entity (other than a wholly-owned Company Subsidiary), other than: (i) in connection with refinancings of indebtedness existing as of the date of this Agreement or indebtedness otherwise incurred in compliance with this Section 5.2(a) at or within six months of its stated maturity or at a lower cost of funds (calculating such cost on an aggregate after-Tax basis), (ii) short-term indebtedness (including commercial paper and borrowings under revolving credit facilities) incurred to refinance short-term indebtedness and indebtedness of the Company or any of its directly or indirectly wholly-owned Subsidiaries to the Company or any of the Company Subsidiaries, (iii) letters of credit, surety bonds or guarantees of payment or performance obligations of the Company or any of the Company Subsidiaries in the ordinary course of business or (iv) drawings under existing credit facilities or replacement of borrowings under existing credit facilities; or borrowings evidenced by commercial paper that is back-stopped by existing credit facilities;

(b) (i) adjust, split, combine or reclassify any of its capital stock, except for any such transaction by a wholly-owned Company Subsidiary which remains a wholly-owned Company Subsidiary after the transaction and does not adversely affect the Company;

(ii) make, declare or pay any dividend other than such dividends that have been declared as of the date hereof, or make any other distribution on, or directly or indirectly redeem, purchase or otherwise acquire, any shares of its capital stock or any securities or obligations convertible (whether currently convertible or convertible only after the passage of time or the occurrence of certain events) into or exchangeable for any shares of its capital stock (except for (A) regular quarterly cash dividends paid by the Company, not in excess of, with respect to each quarter, $0.51 per Share, with usual declaration, record and payment dates and in a manner consistent with the Company's past dividend policy, (B) dividends payable by the Company Subsidiaries to the Company or to any wholly-owned Company Subsidiaries, (C) in connection with the exercise of Company Stock Options or Tax withholdings on the vesting or payment of Company Stock Awards in accordance with the terms of the applicable award agreements or the Company Equity Incentive Plan pursuant to which the awards were granted, (D) dividend equivalent rights on Company Stock Awards payable by the Company consistent with past practice and the applicable award agreements and (E) repurchases or cancellations of unvested Shares in connection with the forfeiture of any Company Stock Awards;

(iii) grant any Company Stock Option, restricted stock, stock appreciation rights or grant any individual, corporation or other entity any right to acquire any shares of its capital stock, except as described in Section 5.2(b)(iii) of the Company Disclosure Letter;

(iv) allow the commencement of any new Offering Period except in the ordinary course of business;

(v) issue any additional Shares except upon the exercise of Company Stock Options or ESPP Purchase Rights, in connection with the vesting or payment of Company Stock Awards or under the Company DRIP;

(c) except in the ordinary course of business consistent with the Company's current policies and procedures and historical practices, or as required by an agreement (including, any Company Benefit Plan or collective bargaining agreement) in effect on the date of this Agreement or the Company Equity Incentive Plan or as otherwise set forth in Section 5.2(c) of the Company Disclosure Letter:

(i) increase any wages, salaries, compensation, pension, or other fringe benefits or perquisites payable to any director, executive officer or Employee (it being understood that, in the case of incentive compensation, an increase in compensation refers to an increase in target opportunity, rather than the amount paid based on actual performance);

(ii) enter into or amend any employment or severance agreements with any director or executive officer;

(iii) establish any bonus or incentive plan;

(iv) pay any pension or retirement allowance not allowed by any Company Benefit Plan or other similar arrangement in effect as of the date of this Agreement;

(v) pay any bonus to any director or executive officer of the Company;

(vi) become a party to, amend or commit itself to, any pension, retirement, profit-sharing or welfare benefit plan or agreement or employment agreement with or for the benefit of any Employee; or

(vii) accelerate the vesting of, or the lapsing of restrictions with respect to, any Company Stock Awards (except as provided in Section 2.3);

(d) except in the ordinary course of business, sell, lease, transfer or otherwise dispose of any of its material properties or assets in the aggregate, to any Person other than a Company Subsidiary;

(e) (i) waive, release or assign its rights with respect to any Action in which the Company or any Company Subsidiary is seeking material monetary damages; (ii) compromise, settle or agree to settle any Action or investigation in which damages are being sought against the Company or any Company Subsidiary, other than compromises, settlements or agreements that (A) involve only the payment of monetary damages that are not material or (B) if involving any non-monetary outcome, that will not have a material effect on the continuing operations of Parent and the Parent Subsidiaries after the Effective Time (including the Company and the Company

Subsidiaries) or (iii) compromise, settle or agree to settle any Action arising out of the matters described in Section 5.2(e) of the Company Disclosure Letter;

(f) make any acquisition (including by merger) of the capital stock or a material portion of the assets of any other Person for consideration in excess of $20,000,000 individually, or $40,000,000 in the aggregate, except (i) pursuant to Contracts in force on the date of this Agreement and set forth in Section 5.2(f) of the Company Disclosure Letter, (ii) for acquisitions of books of business of retail customers consistent with past practice and valuation multiples and (iii) capital expenditures permitted under clause (g) below;

(g) except as otherwise permitted by the terms of this Agreement, make or commit to make any capital expenditures in the period from the date hereof until December 31, 2015, or in the 12-month period ending December 31, 2016, to the extent that the aggregate capital expenditures of the Company and the Company Subsidiaries would exceed 110% of the amount forecasted for the Company and the Company Subsidiaries during the applicable period, as set forth in Section 5.2(g) of the Company Disclosure Letter, except, that notwithstanding the foregoing, the Company and any Company Subsidiary will be permitted to make emergency capital expenditures in any amount (i) required by a Governmental Entity, (ii) that the Company determines is necessary in its reasonable judgment based on prudent utility practices to maintain or restore the provision of utility service to customers or (iii) that represents amounts included in the capital expenditure forecast with respect to the local distribution company businesses of the Company and the Company Subsidiaries after December 31, 2016 that are being accelerated into an earlier period and represent expenditures that are expected to be recoverable under rider programs and meet the requirements of applicable rider guidelines;

(h) enter into any new line of business that is material to the Company and the Company Subsidiaries, taken as a whole, except in the ordinary course of business;

(i) amend the Company Charter or the Company Bylaws or take any action to exempt any Person (other than Parent or the Parent Subsidiaries) from GBCC Section 14-2-1132, any other Takeover Law or any similarly restrictive provisions of its organizational documents;

(j) except as required by GAAP or any Governmental Entity (including the SEC and the PCAOB) or in the ordinary course of business, make any material change in its methods or principles of accounting;

(k) make, change or rescind any material Tax election, change any Tax accounting period, adopt or change any Tax accounting method, amend any material Tax Return, enter into any material closing agreement, settle any Tax claim or assessment relating to the Company or any of the Company Subsidiaries in an amount that materially exceeds the amount reserved with respect thereto in the most recent Company Financial Statements or obtain any material Tax ruling;

(l) adopt or recommend a plan of complete or partial dissolution, liquidation, recapitalization, restructuring or other reorganization, except for any such transactions between or among wholly-owned Company Subsidiaries;

(m) enter into, or amend in any material respect, any collective bargaining agreement;

(n) fail to make any minimum contributions to any Company Benefit Plan required by the Pension Protection Act of 2006 (or similar legal requirements for plans outside the United States), provided that any contribution in excess of such minimum amount will not exceed $75,000,000 for the period between the date of this Agreement and the Closing;

(o) conduct the businesses of the Company or any Company Subsidiary in a manner that would cause the Company or any Company Subsidiary to become an "investment company" subject to registration under the Investment Company Act;

(p) make any changes or propose any changes in its rates or charges, standards of service or regulatory accounting from those in effect on the date of this Agreement, or make any filing to change its rates on file with the State Commissions, except for any change or filing (i) which is not reasonably expected to materially lower the authorized return on equity in respect of the Company's (including the Company Subsidiaries) regulated business, (ii) required by applicable Law or (iii) which would not reasonably be expected to lead to any material delay in obtaining or materially increase the risk of not obtaining any of the Regulatory Approvals (it being understood and agreed that, in the case of each of clause (i), (ii) and (iii) above, the Company will provide Parent such application reasonably in advance of filing and will consider Parent's comments in good faith prior to filing such application);

(q) terminate or permit any Permit of the Company or any Company Subsidiary to lapse, other than in accordance with the terms and regular expiration of any such Permit, or fail to apply on a timely basis for any renewal of any renewable Permit of the Company, except to the extent such termination, lapse or failure to apply for renewal would not reasonably be expected to have a Company Material Adverse Effect;

(r) (i) amend or modify in any material respect the Company Trading Guidelines in a manner that results in such Company Trading Guidelines being materially less restrictive than the Company Trading Guidelines in effect on the date hereof, except for any amendment or modification necessary to manage an increase in volatility in the ordinary course of business consistent with past practice, (ii) terminate the Company Trading Guidelines other than in the ordinary course of business consistent with past practice; except, that in the case of any such termination, new Company Trading Guidelines are adopted that are at least as restrictive as the Company Trading Guidelines in effect on the date hereof or (iii) take any action that violates the Company Trading Guidelines or cause or permit the Net Company Position to be outside the risk parameters set forth in the Company Trading Guidelines (other than as a result of movement in market price); and if at any time the Net Company Position becomes outside the risk parameters set forth in the Company Trading Guidelines due to a move in market prices, fail to take action to bring the Net Company Position back inside the parameters as required by the Company Trading Guidelines;

(s) (i) amend or terminate any lease Contract in respect of Company Leased Real Property in a manner that would have a material and adverse effect on the Company or any Company Subsidiary, except in each case pursuant to existing Contracts, (ii) enter into any Contract that would materially restrain, limit or impede the Company or any Company Subsidiary with respect to engaging in any line of business or geographic area or (iii) take any action (or fail to take any action necessary) in violation of any order or regulation of any Governmental Entity governing the Company's (including the Company Subsidiaries) operations that would constitute a Company Material Adverse Event; or

(t) agree to take, make any commitment to take, or adopt any resolutions of the Company Board or board of directors (or equivalent body) of such Company Subsidiary, as applicable, in support of, any of the actions prohibited by this Section 5.2.

ARTICLE VI

ADDITIONAL AGREEMENTS

Section 6.1 Filings; Other Actions; Notification.

(a) Cooperation. Subject to the terms and conditions set forth in this Agreement, the Company and Parent will cooperate with each other and use (and will cause their respective Subsidiaries to use) their respective reasonable best efforts to take or cause to be taken all actions, and do or cause to be done all things, reasonably necessary, proper or advisable on its part under this Agreement and applicable Laws to consummate the Transactions as soon as practicable, including preparing and filing as promptly as practicable all documentation to effect all necessary notices, reports and other filings and to obtain as promptly as practicable all consents, registrations, approvals, permits and authorizations necessary or advisable to be obtained from any third party or Governmental Entity in order to consummate the Transactions. Parent will bear and pay the costs and expenses (other than attorneys' fees and expenses) incurred in connection with the filings of the premerger notification and report forms under the HSR Act (including filing fees). Subject to applicable Laws relating to the exchange of information, Parent and the Company will have the right to review in advance and, to the extent practicable, each will consult with the other on and consider in good faith the views of the other in connection with, all of the information relating to Parent or the Company, as the case may be, and any of their respective Subsidiaries, that appears in any filing made with, or written materials submitted to, any third party or any Governmental Entity in connection with the Transactions (including the Proxy Statement). In exercising the foregoing rights, each of the Company and Parent will act as promptly as practicable. Nothing in this Agreement will require the Company or the Company Subsidiaries to take or agree to take any action with respect to its business or operations unless the effectiveness of such agreement or action is conditioned upon Closing.

(b) Information. Subject to applicable Laws, the Company and Parent each will, upon request by the other, furnish the other with all information concerning itself, its Subsidiaries, directors, officers and shareholders and such other matters as may be reasonably necessary or advisable in connection with the Proxy Statement or any other statement, filing, notice or application made by or on behalf of Parent, the Company, or any of their respective Subsidiaries to any third party or any Governmental Entity in connection with the Transactions, including under the HSR Act and any other applicable antitrust Law; except that either Party may designate information "for outside counsel only" and either Party may redact information related to the value of the transaction. Subject to applicable Laws relating to the exchange of information and except as otherwise provided in this Agreement, Parent and the Company will have the right to review in advance, and to the extent practicable each will consult with the other regarding, and consider in good faith the views of the other in connection with, all of the information relating to Parent or the Company, as the case may be, and any of their respective Affiliates and Representatives, that appears in any filing made with, or written materials submitted to, any Governmental Entity in connection with the Transactions. In exercising the foregoing rights, each of the Company and Parent will act reasonably and as promptly as practicable.

(c) Status. Subject to applicable Laws and the instructions of any Governmental Entity, the Company and Parent each will keep the other apprised of the status of matters relating to completion of the Transactions, including promptly furnishing the other with any information or notices or other correspondence received from any third party or any Governmental Entity with respect to the Transactions; except that either Party may designate information or notices or other communications as "for outside counsel only". Neither the Company nor Parent will permit any of its officers or any other Representatives to participate in or schedule any meeting or substantive telephone discussion with (A) any Governmental Entity in respect of any filings, investigation or other inquiry with respect to the Transactions or (B) any State Commission with respect to any matter that would or would reasonably be expected to materially impact the post-Closing operations of the Company and the Company Subsidiaries, unless to the extent practicable (i) it consults with the other Party in advance and (ii) to the extent permitted by such Governmental Entity, gives the other Party the opportunity to attend and participate in such meeting or substantive telephone discussion and in any event, the Company and Parent will keep each other reasonably apprised of all material substantive communications with any such Governmental Entities of which such Party is aware related to the foregoing.

(d) Regulatory Matters.

(i) Subject to the terms and conditions set forth in this Agreement, without limiting the generality of the other undertakings pursuant to this Section 6.1, each of the Company and Parent agree to take or cause to be taken the following actions:

(A) the prompt provision to each and every federal, state, local or foreign court or Governmental Entity (including the FCC and State Commissions) with jurisdiction over Regulatory Approval of non-privileged information and documents requested by any such Governmental Entity that are necessary, proper or advisable to permit consummation of the Transactions;

(B) the prompt use of its reasonable best efforts to avoid the entry or enactment of any permanent, preliminary or temporary injunction or other order, decree, decision, determination, judgment or Law that would delay, restrain, prevent, enjoin or otherwise prohibit consummation of the Transactions; and

(C) the prompt use of its reasonable best efforts to take, in the event that any permanent, preliminary or temporary injunction, decision, order, judgment, determination, decree or Law is entered, issued or enacted, or becomes reasonably foreseeable to be entered, issued or enacted, in any proceeding, review or inquiry of any kind that would make consummation of the Transactions in accordance with the terms of this Agreement unlawful or that would delay, restrain, prevent, enjoin or otherwise prohibit consummation of the Transactions, any and all commercially reasonable steps (including the appeal thereof, the posting of a bond or the taking of the steps contemplated by clause (ii) of this Section 6.1(d)) necessary to resist, vacate, modify, reverse, suspend, prevent, eliminate, avoid or remove such actual, anticipated or threatened injunction, decision, order, judgment, determination, decree or enactment so as to permit such consummation as promptly as practicable.

(ii) In furtherance of the requirements of this Section 6.1(d), following the execution and delivery by the Parties of this Agreement, the Company and Parent will, and will cause their respective Subsidiaries to, (A) enter into discussions with the Governmental Entities from whom Regulatory Approvals are required to be obtained in connection with the consummation of the Transactions, (B) use their respective reasonable best efforts to obtain all such required Regulatory Approvals from such Governmental Entities and eliminate each and every other impediment that may be asserted by such Governmental Entities pursuant to any applicable Law or in connection with granting the Regulatory Approvals, in each case with respect to the Transactions, so as to enable the Closing to occur as soon as reasonably possible, and (C) undertake any effort or take any action (including by (1) accepting terms, conditions, liabilities, obligations, commitments or sanctions and proposing, negotiating, committing to and effecting, by consent decree, Order to hold separate for sale or otherwise, the sale, divestiture, licensing or disposition of assets or businesses of Parent or the Company or their respective Subsidiaries and (2) accepting organizational, operational and financial restrictions) necessary or required in order to obtain the Regulatory Approvals, except that nothing in this Agreement will require (and reasonable best efforts will in no event require) Parent or any of its Affiliates to, and, without the prior written consent of Parent (which consent may be withheld at Parent's sole discretion), the Company will not, and will cause its Affiliates not to, offer, accept or agree, or commit to agree, to, any undertaking, term, condition, liability, obligation, commitment or sanction in connection with the consummation of the Transactions that, individually or in the aggregate, constitutes or would reasonably be expected to constitute a Burdensome Effect.

(iii) The Parties will cooperate with one another in seeking to obtain the Regulatory Approvals or any other filings made with or written materials submitted to any Governmental Entity in connection with the Transactions or that would or would reasonably be expected to materially impact the post-Closing operations of the Company or any Company Subsidiary, including in coordinating the timing of all such filings and discussions with Governmental Entities.

(iv) Without the prior written consent of Parent, the Company will not agree to, or accept, any agreements, commitments or conditions in connection with the Merger pursuant to any settlement or otherwise with any Governmental Entity or any other Person. Without the prior written consent of the Company, Parent will not agree to, or accept, any agreements, commitments or conditions in connection with the Merger pursuant to any settlement or otherwise with any Governmental Entity or any other Person affecting the Company or any Company Subsidiaries to the extent any such agreement, commitment or condition is effective prior to the Effective Time.

(v) Nothing in this Section 6.1 will limit any applicable rights a Party may have to terminate this Agreement pursuant to Section 8.1 in a case where Section 8.1 permits such termination.

Section 6.2 Proxy Statement; Shareholder Approval.

(a) As promptly as reasonably practicable following the date of this Agreement, the Company will prepare and file a preliminary Proxy Statement with the SEC. Subject to Section 6.9, the Proxy Statement will include the Company Board Recommendation. Parent will cooperate with the Company in the preparation and filing of the Proxy Statement and will furnish all information concerning it that is necessary in connection with the preparation of the Proxy Statement and is reasonably requested by the Company. The Company will use its reasonable best efforts to have the Proxy Statement cleared by the SEC as promptly as reasonably practicable after such filing and the Company will use its reasonable best efforts to cause the Proxy Statement to be mailed to the Company's shareholders, in each case as promptly as reasonably practicable after the Company learns that the Proxy Statement will not be reviewed or that the SEC staff has no further comments thereon. Prior to filing or mailing the Proxy

Statement or filing any other required documents (or in each case, any amendment or supplement thereto) or responding to any comments of the SEC with respect thereto, the Company will provide Parent with an opportunity to review and comment on such document or response (including by participating in any discussions or meetings with the SEC) and will give good faith consideration to any comments made by Parent and its counsel. The Company will notify Parent promptly of the receipt of any comments from the SEC or its staff and of any request by the SEC or its staff for amendments or supplements to the Proxy Statement or for additional information and will supply Parent with copies of all correspondence between the Company and the SEC or its staff with respect to the Proxy Statement or the Transactions.

(b) If, at any time prior to obtaining the Company Shareholder Approval, any information relating to the Company or Parent, or any of their respective Affiliates, officers or directors, is discovered by the Company or Parent that should be set forth in an amendment or supplement to the Proxy Statement so that such document would not include any misstatement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements made therein, in light of the circumstances under which they are made, not misleading, the Party that discovers such information will as promptly as practicable notify the other Party and an appropriate amendment or supplement describing such information will be filed with the SEC as promptly as practicable after the other Party has had a reasonable opportunity to review and comment thereon, and, to the extent required by applicable Law, disseminated to the shareholders of the Company. The Proxy Statement will comply as to form and substance in all material respects with the applicable requirements of the Exchange Act and other applicable Law, including the regulations and requirements of NYSE.

(c) The Company will call a meeting of its shareholders to be held as soon as reasonably practicable after the Proxy Statement is cleared by the SEC staff for mailing to consider and vote on approval of this Agreement and any other matters required to be voted upon by the Company's shareholders in connection with the Transactions (including any adjournment or postponement thereof, the "Company Shareholders Meeting"). Subject to and until the Company Board effects a Change of Recommendation pursuant to Section 6.9(c), the Company Board will use its reasonable best efforts to obtain from its shareholders the Company Shareholder Approval. Subject to Section 6.9(c), the Company Board will recommend that its shareholders vote in favor of approval of this Agreement (the "Company Board Recommendation"). Subject to the Company's right to terminate this Agreement under Section 8.1(d)(ii), the Company and Parent agree that the Company's obligations pursuant to the first two sentences of this Section 6.2(c) will not be affected by the commencement, public proposal or communication to the Company of any Alternative Proposal, or by the withdrawal or modification by the Company Board of the Company Board Recommendation.

Section 6.3 Access to Information.

(a) Upon reasonable advance notice, the Company will, and will cause each Company Subsidiary to, afford to Parent and to the officers, employees, accountants, counsel, lenders, financial advisors and other Representatives of Parent reasonable access during normal business hours during the period prior to the Effective Time to all the Company's and the Company Subsidiaries' owned or leased properties, books, Contracts, commitments, personnel (including contractors and distributors), records, Tax Returns and all other information concerning its business, operations, status of compliance with Environmental Law, properties and personnel as Parent may reasonably request; except that Parent and its Representatives will conduct any such activities in such a manner as not to interfere unreasonably with the business or operations of the Company and the Company Subsidiaries; and except further that such access will not include any intrusive, invasive or other sampling or testing (including any Phase II environmental assessments) of any environmental media or any physical assets of the Company; and except further that the Company and the Company Subsidiaries will not be required to provide any access or disclose any information if such access or disclosure would (i) contravene any applicable Law, (ii) jeopardize the attorney-client privilege of the institution in possession or control of such information, (iii) result in the disclosure of any Trade Secrets of third parties or (iv) contravene any binding agreement entered into prior to the date of this Agreement.

(b) All information and materials provided pursuant to this Agreement will be subject to the provisions of the Confidentiality Agreement entered into between the Company and Parent as of August 2, 2015 (the "Confidentiality Agreement").

(c) No investigation by either of the Parties or their respective Representatives will affect the representations and warranties of the other set forth in this Agreement.

Section 6.4 Employee Matters.

(a) Continuation of Compensation and Benefits. Parent will, and will cause its Affiliates to, continue the employment effective immediately after the Closing Date of all Employees of the Company or any Company Subsidiary as of the Closing Date (the "Company Employees"), including each such Employee on medical, disability, family or other leave of absence as of the Closing Date. For a period of one year following the Effective Time (the "Continuation Period"), Parent will, or will cause its Affiliates to, provide each Company Employee with compensation and benefits that are no less favorable in the aggregate than the compensation and benefits, taken as a whole (including equity-based compensation opportunities and severance benefits), provided to such Company Employee as of immediately prior to the Effective Time; except that each such Company Employee's annual base salary or wage rate will be no less favorable than those provided to such Company Employee as of the Effective Time. Nothing in this Section 6.4(a) will obligate Parent, Surviving Corporation or the Company to continue the employment of any Company Employee for any specific period.

(b) Employee Service Credit. Parent will, and will cause its Affiliates to, (i) give each Company Employee credit for service with the Company and any Company Subsidiary or predecessor employer prior to the Closing Date, to the same extent recognized by the Company or any Company Subsidiary in a comparable Company Benefit Plan, under any employee benefit plans or personnel policies maintained by Parent or its Affiliates, for all purposes (including eligibility to participate, vesting in eligible benefits and levels of benefits) other than for benefit accrual purposes under a defined benefit pension plan; except that Company Employees will not be entitled to the benefit of any grandfathered benefit formula that would not be provided to any employee first hired by Parent on or after the Effective Time, (ii) allow each Company Employee to participate in each Company Benefit Plan and any employee benefit plan maintained by Parent or its Affiliates providing welfare benefits (including medical, life insurance, long-term disability insurance and long-term care insurance) in the plan year in which the Closing occurs without regard to preexisting-condition limitations, waiting periods, evidence of insurability or other exclusions or limitations, and (iii) credit each Company Employee in the plan year in which the Effective Time occurs with any expenses that were covered by the Company Benefit Plans for purposes of determining deductibles, co-pays and other applicable limits under each Company Benefit Plan with respect to any employee benefit plan maintained by Parent or its Affiliates in which such Company Employee participates during such plan year in which the Effective Time occurs.

(c) Vacation Pay and Personal Holidays. From and after the Effective Time, Parent will, and will cause its Affiliates to, continue to credit to each Company Employee all vacation and personal holiday pay that such Company Employee is entitled to use but has not used as of the Closing Date (including any earned vacation or personal holiday pay to be used in future years) subject to Parent's vacation day carryover policy, beginning with the year following the year in which the Effective Time occurs.

(d) Certain Commitments. From and after the Effective Time, Parent will, and will cause its Affiliates to, treat the Transactions as constituting a "change in control," "change of control" or similar terms under the Company Benefit Plans and any such other Company compensation and severance arrangements or agreements.

(e) Bonus Plans. Parent will, and will cause its Affiliates to, operate the Company's annual incentive plan and all other annual bonus arrangements (collectively, "Bonus Plans"), in effect on the date hereof, or such future plans as may be established by the Compensation Committee of the Company Board, consistent with the parameters set forth on Section 6.4(e) of the Company Disclosure Letter, for annual performance periods commencing after the date hereof and running through the Effective Time, which such future plans will be consistent with the Company and the Company Subsidiaries' business plans and past practice. With respect to the remainder of the fiscal year for the fiscal year in which the Effective Time occurs, Parent will, and will cause its Affiliates, to permit Company Employees to participate on a pro rata basis in Parent bonus arrangements in accordance with terms established in the ordinary course.

(f) Retention Plan. Prior to the Effective Time, Parent will establish a retention plan for the benefit of certain employees of the Surviving Corporation. In addition, the Company and Parent agree to cooperate in taking additional actions in order to promote the retention and ensure the continuity of key management, which may include the amendment of certain existing continuity agreements entered into between the Company and certain members of key management and the grant of certain retention equity awards in connection therewith.

(g) No Third Party Beneficiaries. Nothing in this Section 6.4 will create any right or obligation which is enforceable by any Employee or any other Person with respect to any terms or conditions of employment, including the benefits and compensation described in this Section 6.4. For the avoidance of doubt, any amendments to the Company's, the Company Subsidiaries', Parent's and the Surviving Corporation's benefit and compensation plans, programs or arrangements will occur only in accordance with their respective terms and will be pursuant to action taken by the Company, the Company Subsidiaries, Parent or the Surviving Corporation which are independent of the consummation of this Agreement or any continuing obligations hereunder.

Section 6.5 Indemnification; Directors' and Officers' Insurance.

(a) From the Effective Time and ending on the sixth anniversary of the Effective Time, Parent will cause the Surviving Corporation to indemnify, defend and hold harmless (including by advancing expenses) each current and former director and officer of the Company and any of the Company Subsidiaries, each Employee and each person who served as a director, officer, member, trustee or fiduciary of another corporation, partnership, joint venture, trust, pension or other employee benefit plan or enterprise if such service was at the request or for the benefit of the Company or any of the Company Subsidiaries (each, an "Indemnified Party" and, collectively, the "Indemnified Parties") against all claims, liabilities, losses, damages, judgments, fines, penalties, costs and expenses (including fees and expenses of legal counsel) in connection with any actual or threatened claim, suit, action, proceeding or investigation (whether civil, criminal, administrative or investigative) (each, a "Claim"), whenever asserted, arising out of, relating to or in connection with any action or omission relating to their position with the Company or the Company Subsidiaries occurring or alleged to have occurred before or at the Effective Time (including any Claim relating in whole or in part to the Agreement or the Transactions), to the fullest extent permitted under applicable Law. Each of (x) the respective organizational documents of each of the Company Subsidiaries as currently in effect and (y) any indemnification agreements with an Indemnified Party listed on Section 6.5(a) of the Company Disclosure Letter, which will in each case survive the Transactions and continue in full force and effect to the extent permitted by applicable Law, will not, for a period of six years from the Effective Time, be amended, repealed or otherwise modified in a manner that would adversely affect the rights thereunder of the Indemnified Parties except, in the case of clauses (x) and (y), as required by applicable Law. Without limiting the foregoing, at the Effective Time, the Surviving Corporation will, and Parent will cause the Surviving Corporation to cause the certificate of incorporation and by-laws of the Surviving

Corporation to include provisions for limitation of liabilities of Indemnified Parties, indemnification, advancement of expenses and exculpation of the Indemnified Parties no less favorable to the Indemnified Parties than as set forth in the Company Charter and Company Bylaws in effect on the date of this Agreement, which provisions will, for a period of six years from the Effective Time, not be amended, repealed or otherwise modified in a manner that would adversely affect the rights thereunder of the Indemnified Parties except as required by applicable Law.

(b) Prior to the Effective Time, the Company will and, if the Company is unable to, Parent will cause the Surviving Corporation as of the Effective Time to obtain and fully pay for "tail" insurance policies with a claims period of at least six years from and after the Effective Time from the Company's current insurance carrier or from an insurance carrier with the same or better credit rating as the Company's current insurance carrier with respect to directors' and officers' liability insurance and fiduciary liability insurance (the "D&O Insurance") for the persons who, as of the date of this Agreement, are covered by the Company's existing D&O Insurance. Such "tail" insurance policies will have terms, conditions, retentions and levels of coverage at least as favorable as the Company's existing D&O Insurance with respect to matters existing or occurring at or prior to the Effective Time (including in connection with this Agreement and the Transactions). Parent will cause the Surviving Corporation to maintain such "tail" insurance policies in full force and effect for their full term. If the Company and the Surviving Corporation for any reason fail to obtain such "tail" insurance policies as of the Effective Time, the Surviving Corporation will, and Parent will cause the Surviving Corporation to, continue to maintain in effect, at no expense to the Indemnified Parties, for a period of at least six years from and after the Effective Time, the Company's D&O Insurance in place as of the date of this Agreement with terms, conditions, retentions and levels of coverage at least as favorable as provided in the Company's existing policies as of the date of this Agreement, or, if such insurance is unavailable, the Surviving Corporation will, and Parent will cause the Surviving Corporation to, purchase the best available D&O Insurance for such six-year period from an insurance carrier with the same or better credit rating as the Company's current insurance carrier with respect to the Company's existing D&O Insurance with terms, conditions, retentions and with levels of coverage at least as favorable as provided in the Company's existing policies as of the date of this Agreement; except that neither Parent nor the Surviving Corporation will be required to pay an aggregate premium for such insurance policies in excess of $3,500,000; and if the premiums of such insurance coverage exceed such amount, Parent or the Surviving Corporation will be obligated to obtain a policy with the greatest coverage available for a cost not exceeding such amount.

(c) The provisions of this Section 6.5 are (i) intended to be for the benefit of, and will be enforceable by, each Indemnified Party, his or her heirs and his or her representatives and (ii) in addition to, and not in substitution for or limitation of, any other rights to indemnification or contribution that any such Person may have by Contract or otherwise.

(d) In the event that Parent, the Surviving Corporation or any of their respective successors or assigns (i) consolidates with or merges into any other Person and is not the continuing or surviving corporation or entity of such consolidation or merger or (ii) transfers or conveys all or substantially all of its properties and assets to any Person, then, and in each such case, proper provision will be made so that the successors and assigns of Parent and the Surviving Corporation, as applicable, will assume all of the obligations thereof set forth in this Section 6.5.

Section 6.6 Additional Agreements. Subject to the terms and conditions of this Agreement, in case at any time after the Effective Time any further action is necessary or desirable to carry out the purposes of this Agreement or to vest the Surviving Corporation with full title to all properties, assets, rights, approvals, immunities and franchises of the Company, the then-current officers and directors of each of the Company and the Company Subsidiaries will use their respective reasonable best efforts to take all such actions as may be reasonably requested by Parent.

Section 6.7 Advice of Changes. Each of Parent and the Company will promptly advise the other of any change or event, of which it has knowledge, (a) having or reasonably likely to have a Parent Material Adverse Effect or a Company Material Adverse Effect, as the case may be, or (b) that would or would be reasonably likely to cause or constitute a material breach of any of its representations, warranties or covenants contained in this Agreement if it would result in the failure of closing conditions in Section 7.3(a) or Section 7.3(b), or Section 7.2(a) or Section 7.2(b), respectively, by the Outside Date, except that (i) no such notification will affect the representations, warranties or covenants of the Parties (or remedies with respect thereto) or the conditions to the obligations of the Parties under this Agreement and (ii) a failure to comply with this Section 6.7 will not constitute the failure of any condition set forth in Article VII to be satisfied unless the underlying Parent Material Adverse Effect, Company Material Adverse Effect or material breach would independently result in the failure of a condition set forth in Article VII to be satisfied. The Company will promptly advise Parent of all developments in, and the receipt of all communications from any Governmental Entities with respect to, the matters described in Section 5.2(e) of the Company Disclosure Letter. The Company will provide Parent with copies of all submissions to any Governmental Entity with respect to such matters, and provide Parent with the opportunity to participate in the preparation for all meetings with any Governmental Entity with respect to such matters.

Section 6.8 Section 16 Matters. Prior to the Effective Time, each of Parent and the Company will take all such steps as may reasonably be necessary or advisable to cause the Transactions, including any dispositions of Shares (including derivative securities with respect to such Shares) by each individual who is or will be subject to the reporting requirements of Section 16(a) of the Exchange Act with respect to the Company, to be exempt under Rule 16b-3 promulgated under the Exchange Act.

Section 6.9 No Solicitation or Change of Recommendation.

(a) No Solicitation.

(i) Except as set forth in Section 6.9(a)(ii) and Section 6.9(a)(iii), the Company agrees that none of the Company, any of the Company Subsidiaries, nor any of their respective officers, managers or directors (collectively, the "Company Non-Solicit Parties") will, and that they will instruct and cause their respective Affiliates and Representatives not to, directly or indirectly:

(A) initiate, solicit or knowingly facilitate or encourage any inquiries, discussions regarding, or the making or submission of, any proposal, request or offer that constitutes, or could reasonably be expected to lead to, any Alternative Proposal;

(B) approve, endorse, recommend or enter into any Contract or agreement in principle, whether written or oral, with any Person (other than Parent and Merger Sub) concerning any letter of intent, memorandum of understanding, acquisition agreement, merger agreement, joint venture agreement, partnership agreement or other similar Contract concerning an Alternative Proposal (other than negotiating and entering into a confidentiality and standstill agreement as described in Section 6.9(a)(iii)) (an "Alternative Acquisition Agreement");

(C) terminate, amend, release, modify, or fail to enforce any provision of, or grant any permission, waiver or request under, any standstill, confidentiality or similar Contract entered into by the Company or a Company Subsidiary in respect of or in contemplation of an Alternative Proposal (other than to the extent the Company Board determines in good faith, after consultation with its outside financial and legal advisors, that failure to take any such actions under this Section 6.9(a)(i)(C) would be inconsistent with the directors' fiduciary duties or obligations under applicable Law);

(D) conduct, engage in, continue or otherwise participate in any discussions or negotiations regarding any Alternative Proposal (other than with the Company's Representatives);

(E) furnish any non-public information relating to the Company, or afford access to the books or records or Representatives of the Company, to any third party that, to the knowledge of the Company, after consultation with its Representatives, is seeking to or may make, or has made, an Alternative Proposal;

(F) take any action to make the provisions of any Takeover Laws inapplicable to any transactions contemplated by any Alternative Proposal; or

(G) resolve or publicly propose or announce to do any of the foregoing.

Notwithstanding the foregoing, nothing in this Section 6.9(a)(i) will prohibit the Company Non-Solicit Parties from contacting any Person who has made a Bona Fide Alternative Proposal solely to request clarification of the terms and conditions thereof to the extent necessary to permit the Company Board to determine whether such Bona Fide Alternative Proposal either constitutes a Superior Proposal or could reasonably be expected to result in a Superior Proposal.

(ii) Notwithstanding anything to the contrary in this Agreement and subject to the conditions in Section 6.9(a)(iii) and solely in response to a Bona Fide Alternative Proposal made on or after the date of this Agreement and prior to the Company Shareholder Approval, the Company Non-Solicit Parties may, with respect to the Person that has made such Bona Fide Alternative Proposal:

(A) in response to a request therefor by such Person, provide information or afford access to the books and records or Representatives of the Company, to such Person (and its Representatives); and

(B) engage or participate in discussions or negotiations with such Person (and its Representatives) with respect to such Bona Fide Alternative Proposal.

(iii) The Company may not take the actions described in Section 6.9(a)(ii) unless, prior to taking any such action:

(A) the Company has received from such Person an executed confidentiality and standstill agreement on terms that are no less restrictive than those contained in the Confidentiality Agreement (and compliant with the last sentence of Section 6.9(g));

(B) the Company has delivered to Parent written notice prior to taking any such action (1) stating that the Company Board intends to take such action and (2) stating that the Company Board has made the determination set forth in Section 6.9(a)(iii)(C); and

(C) the Company Board has determined in good faith, after consultation with its outside financial and legal advisors, that such Bona Fide Alternative Proposal either constitutes a Superior Proposal or is reasonably likely to result in a Superior Proposal.

(iv) Without limiting Section 6.9(a)(iii), if the Company provides any non-public information to any Person in reliance on Section 6.9(a)(ii) that has not previously been provided to Parent, then the Company will provide such information promptly to Parent.

(b) No Change of Recommendation. Except as set forth in Section 6.9(c), no Company Non-Solicit Party will:

(i) withdraw, qualify or modify, in a manner adverse to Parent or Merger Sub, the Company Board Recommendation;

(ii) fail to announce publicly, within 10 Business Days after a tender offer or exchange offer relating to any securities of the Company has been commenced, that the Company Board recommends rejection of such tender or exchange offer;

(iii) fail to include the Company Board Recommendation in the Proxy Statement distributed to the Company's shareholders in connection with the Transactions;

(iv) approve, adopt or recommend any Alternative Proposal; or

(v) resolve or publicly propose to do any of the foregoing (any such prohibited action described in Section 6.9(b)(i) through this Section 6.9(b)(v) being referred to as a "Change of Recommendation");

except that the making of any determination of the Company Board (or any committee thereof) to provide, or the provision of, a Superior Proposal Notice or an Intervening Event Notice in compliance with the terms of this Agreement will not, in and of itself, be deemed a Change of Recommendation.

(c) Certain Permitted Changes of Recommendation. Subject to Section 6.9(d), at any time prior to receiving the Company Shareholder Approval, the Company Board may effect, or cause the Company to effect, as the case may be, a Change of Recommendation if: (i) the Company Board determines (A) that after complying with Section 6.9(d)(i), a Bona Fide Alternative Proposal constitutes a Superior Proposal or (B) after complying with Section 6.9(d)(ii), an Intervening Event has occurred and is continuing and (ii) the Company Board determines in good faith, after consultation with its outside financial and legal advisors, that, in light of such Superior Proposal or Intervening Event, as the case may be, (A) the Transactions are not in the best interests of the Company's shareholders and (B) the failure to effect such Change of Recommendation would be inconsistent with the directors' fiduciary duties or obligations under applicable Law.

(d) Procedure Prior to Change of Recommendation.

(i) Superior Proposal. The Company Board will be entitled to effect, or cause the Company to effect, prior to receiving the Company Shareholder Approval, a Change of Recommendation in connection with a Superior Proposal (to the extent permitted under Section 6.9(c)), only if (A) the Company has delivered to Parent a written notice (a "Superior Proposal Notice") (1) stating that the Company Board intends to take such actions pursuant to Section 6.9(c), (2) stating that the Company Board has made the determinations set forth in Section 6.9(c)(i)(A) and Section 6.9(c)(ii) and (3) including an unredacted copy of such Superior Proposal and an unredacted form of any proposed Alternative Acquisition Agreement related to such Superior Proposal and (B) the Negotiation Period has expired. During the four Business Day period commencing on the date of Parent's receipt of such Superior Proposal Notice (such period, as may be extended pursuant to this Section 6.9(d)(i), the "Negotiation Period"), the Company will engage, and will cause its Representatives to be available for the purpose of engaging, in good faith negotiations with Parent (to the extent Parent desires to negotiate) regarding an amendment of this Agreement so that the Alternative Proposal that is the subject of the Superior Proposal Notice ceases to be a Superior Proposal. Each time the financial or other material terms or conditions of such Bona Fide Alternative Proposal (or terms or conditions related thereto, such as the proposed equity and debt financing) are amended or modified, the Company will be required to deliver to Parent a new Superior Proposal Notice (including, as attachments thereto, amended forms of the written Alternative Acquisition Agreements relating to such Bona Fide Alternative Proposal) and the Negotiation Period will be extended by an additional two Business Days from the date of Parent's receipt of such new Superior Proposal Notice.

(ii) The Company Board will be entitled to effect, or cause the Company to effect, a Change of Recommendation in connection with an Intervening Event (to the extent permitted under Section 6.9(c)), only if (A) the Company has delivered to Parent a written notice (an "Intervening Event Notice") (1) stating that the Company Board intends to take such actions pursuant to Section 6.9(c), (2) stating that the Company Board has made the determinations set forth in Sections 6.9(c)(i)(B) and 6.9(c)(ii) and (3) including a summary, in all material respects, of the Intervening Event and (B) the Intervening Event Negotiation Period has expired. During the four Business Day period commencing on the date of Parent's receipt of such Intervening Event Notice (such period, as may be extended pursuant to this Section 6.9(d)(ii), the "Intervening Event Negotiation Period"), the Company will engage, and will cause its Representatives to be available for the purpose of engaging, in good faith negotiations with Parent (to the extent Parent desires to negotiate) regarding an amendment of this Agreement so that the Company Board would no longer be permitted to take such actions pursuant to Section 6.9(c). Each time there is a material change to the facts or circumstances relating to the Intervening Event, the Company will be required to deliver to Parent a new Intervening Event Notice (including, as attachments thereto, a summary of the changes to the facts and circumstances relating to the Intervening Event) and the Intervening Event Negotiation Period will be extended by an additional two Business Days from the date of Parent's receipt of such new Intervening Event Notice.

(e) Certain Permitted Disclosure. Nothing contained in Section 6.9(a) will be deemed to prohibit the Company or the Company Board (or any committee thereof) from (i) complying with Rule 14d-9 or Rule 14e-2(a) promulgated under the Exchange Act, including any "stop, look and listen" communication to the stockholders of the Company pursuant to Rule 14d-9(f) under the Exchange Act, or (ii) making any disclosure to the stockholders of the Company if, in the good faith judgment of the Company Board (after consultation with outside legal counsel) failure to do so would be inconsistent with the directors' fiduciary duties or obligations under applicable Law; except that any such position or disclosure will be deemed a Change of Recommendation unless the Company Board expressly and concurrently reaffirms the Company Board Recommendation.

(f) Existing Discussions. The Company will, and will cause its Subsidiaries and its and their respective Representatives to, immediately cease and cause to be terminated any discussions or negotiations with, or any solicitation or intentional assistance or encouragement of, any Person with respect to any Alternative Proposal (or that could reasonably be expected to lead to or result in an Alternative Proposal) which are on-going as of the date of this Agreement and request that any such Person promptly return and destroy (and confirm destruction of) all confidential information concerning the Company. The Company will take the necessary steps to promptly inform, on the date of this Agreement, the individuals or entities referred to in the preceding sentence of this Section 6.9(f).

(g) Notice. Without limiting anything in this Section 6.9, the Company will promptly (and, in any event, within 24 hours) notify Parent orally and in writing if (i) any inquiries, proposals or offers with respect to an Alternative Proposal or requests for non-public information relating to the Company (other than requests for information in the ordinary course of business consistent with past practice and unrelated to an Alternative Proposal) are received by, or any discussions or negotiations with respect to an Alternative Proposal are sought to be initiated or continued with, the Company or any of its respective Representatives, indicating, in connection with such notice, the name of such Person and the material terms and conditions of such inquiries, proposals or offers, and including in the written version of such notice, an unredacted copy of any written (including via electronic transmission) inquiries, proposals or offers (including (A) any confidentiality and standstill agreement described in Section 6.9(a)(iii) and (B) any materials related to financing with respect to the Alternative Proposal, including amendments and modifications to either of the foregoing, except that any such materials relating to financing with respect to an Alternative Proposal may be redacted in a manner equivalent to Parent's Debt Commitment Letters referred to in Section 4.6), in each case, including any amendments or modifications thereto or (ii) any events or circumstances occur that have caused, or would reasonably be expected to cause, an Intervening Event, including any material changes in any such events or circumstances. The Company will promptly (and, in any event, within 24 hours after any amendment or modification of any such inquiry, proposal or offer or Alternative Proposal) notify Parent orally and in writing of any amendments or modifications thereto and furnish an unredacted copy of any such written (including via electronic transmission) amendments or modifications. The Company will not, and will cause its respective Subsidiaries and Representatives not to, enter into any Contract that would prohibit the Company from providing the information required to be provided to Parent pursuant to this Section 6.9(g).

Section 6.10 Control of the Other Party's Business. Nothing contained in this Agreement will give Parent, directly or indirectly, the right to control or direct the operations of the Company or the Company Subsidiaries or will give the Company, directly or indirectly, the right to control or direct the operations of Parent or its Subsidiaries prior to the Effective Time. Prior to the Effective Time, each of Parent and the Company will exercise, consistent with the terms and conditions of this Agreement, complete control and supervision over its and its Subsidiaries' respective operations.

Section 6.11 Subsidiary Compliance. Parent will cause the payment, performance and discharge by Merger Sub of, and the compliance by Merger Sub with, all of the covenants, agreements, obligations and undertakings of Merger Sub under this Agreement in accordance with the terms of this Agreement. Parent will, promptly following execution of this Agreement, cause the sole shareholder of Merger Sub to approve this Agreement in its capacity as sole shareholder of Merger Sub and deliver to the Company evidence of its vote or action by written consent approving this Agreement in accordance with applicable Law and the articles of incorporation and bylaws of Merger Sub. During the period from the date of this Agreement through the Effective Time, Merger Sub will not, and Parent will not permit Merger Sub to, engage in any activity of any nature except as contemplated by this Agreement.

Section 6.12 Financing.

(a) Parent will use its reasonable best efforts to take, or cause to be taken, all actions and to do, or cause to be done, all things necessary, proper or advisable to arrange and obtain the Financing which, together with cash on hand, will permit Parent to pay the aggregate Merger Consideration and any other cash amounts payable pursuant to, or in connection with, the Transactions, including using reasonable best efforts to (i) negotiate and enter into the Financing Agreements and (ii) satisfy (or, if deemed advisable by Parent, seek a waiver of) on a timely basis all conditions within the control of Parent and required to be satisfied by it, and otherwise comply with all terms applicable to Parent, in the Financing Agreements.

(b) The Company will provide to Parent, and will cause the Company Subsidiaries to provide, in each case, at Parent's sole cost and expense as provided in Section 6.12(d), and will use reasonable best efforts to cause its Representatives to (and use reasonable best efforts to cause external auditors to) provide (x) all cooperation reasonably requested by Parent that is customary, necessary or advisable in connection with arranging, obtaining and syndicating the Financing and any other financing or refinancing transactions undertaken by Parent or any Parent Subsidiary to the extent that information relating to, or the participation by members of management of, the Company is reasonably necessary in connection therewith and causing the conditions in the Financing Agreements to be satisfied and (y) provide all information and assistance that is customarily provided in financings comparable to the proposed Financing or such other financing or refinancing transaction, as the case may be, including using reasonable best efforts in (i) assisting with, and designating one member of senior management of the Company to participate in, the preparation of offering and syndication documents and materials, including registration statements, prospectuses, private placement memoranda, bank information memoranda, bank syndication material and packages, lender and investor presentations, rating agency materials and presentations, and similar documents and materials, in connection with the Financing, and providing reasonable and customary authorization letters to the Financing Sources authorizing the distribution of information to prospective lenders and containing customary information (all such documents and materials, collectively, the "Offering Documents"), (ii) furnishing promptly to Parent all Required Information as may be reasonably requested by Parent to assist in the preparation of the Offering Documents (including execution of customary authorization and management representation letters), (iii) designating one member of senior management of the Company to participate in due diligence sessions and one or more road shows, (iv) assisting Parent in obtaining any corporate credit and family ratings and, if applicable, facility ratings from any ratings agency contemplated by the Debt Commitment Letters, (v) requesting the Company's independent auditors to cooperate with Parent's reasonable best efforts to obtain accountant's comfort letters and consents from the Company's independent auditors, (vi) assisting in the preparation of, and executing and delivering, Financing Agreements and related definitive documents, including guarantees (if required) and other certificates and documents as may be requested by Parent, (vii) cooperating with Parent in seeking from the Company's existing lenders such waivers or payoff letters which may be reasonably requested by Parent in connection with the Financing, (viii) providing at least five Business Days prior to the Closing all documentation and other information about the Company or any of the Company Subsidiaries or Affiliates required by applicable "know your customer" and anti-money laundering rules and regulations, including the USA PATRIOT Act, to the extent reasonably requested at least 10 Business Days prior to the anticipated Closing, and (ix) taking all corporate actions, subject to the occurrence of the Effective Time, reasonably requested by Parent to permit the consummation of the Financing and to permit the proceeds thereof to be made available to the Surviving Corporation immediately upon the Effective Time, except that (A) nothing in this Section 6.12(b) will require such cooperation to the extent it would interfere unreasonably with the business or operations of the Company or the Company Subsidiaries, (B) no obligation of the Company or any Company Subsidiary under any certificate, document, agreement or instrument (other than the authorization and representation letters referred to above) will be effective until the Effective Time and, none of the Company or any Company Subsidiary will be required to pay any commitment or other similar fee or incur any other liability (other than in connection with the authorization and representation letters referred to above) in connection with the Financing prior to the Effective Time and (C) none of the Company Board or board of directors (or equivalent bodies) of any Company Subsidiary will be required to adopt or enter into any resolutions or take similar action approving the Financing (except that concurrently with the Closing the boards (or their equivalent bodies) of Company Subsidiaries may adopt resolutions or take similar actions that do not become effective until the Effective Time). Parent and Parent Subsidiaries will indemnify and hold harmless the Company and the Company Subsidiaries and each of their respective officers, directors, employees, agents, Representatives, successors and assigns from and against any and all damages, fees, costs and expenses suffered or incurred by them other than those liabilities, damages, fees, costs and expenses arising out of a material misstatement in or failure to state a material fact pertinent to the information provided by or on behalf of the Company pursuant to this Section 6.12(b), in connection with the arrangement of the Financing or the use of any Offering Documents. Upon reasonable request of the Company, the Company and its outside legal counsel will be given reasonable opportunity to review and comment upon the Offering Documents, or any materials for rating agencies, in each case, prepared after the date hereof, that include information about the Company or any Company Subsidiary prepared in connection with the Financing. The Company hereby consents to the use of the Company's and the Company Subsidiaries' logos in connection with the Financing in a form and manner agreed with the Company; except that such logos are to be used solely in a manner that is not intended, or reasonably likely, to harm or disparage the Company or any Company Subsidiary or the reputation or goodwill of the Company or any Company Subsidiary. The Company will, upon request of Parent, use its reasonable best efforts to periodically update any Required Information (to the extent it is available) to be included in any Offering Document to be used in connection with such Financing so that Parent may ensure that any such Required Information does not contain any untrue statement of material fact or omit to state any material fact necessary in order to make the statements contained therein not misleading.

(c) The Company will file with the SEC all Company Reports on Form 10-K and Form 10-Q on or prior to the date on which such Company Reports are required to be filed under the Exchange Act, including any extensions with respect thereto.

(d) Parent will promptly, upon request by the Company, reimburse the Company for all reasonable out-of-pocket costs and expenses (including reasonable attorneys' fees) incurred by the Company or any of the Company Subsidiaries in connection with the cooperation of the Company and the Company Subsidiaries contemplated by Section 6.12(b).

(e) Each of Parent and Merger Sub acknowledge and agree that the obligations of each of Parent and Merger Sub under this Agreement and the Transactions, including the obligations of each of Parent and Merger Sub to consummate the Merger, will not be subject to, or conditioned on, receipt of financing.

Section 6.13 Transaction Litigation. The Company will give Parent prompt notice of any Action commenced or, to the knowledge of the Company, threatened, against the Company or its directors, officers, managers, partners or Affiliates relating to this Agreement or the Merger (collectively, "Transaction Litigation"). The Company will consult with Parent regarding the defense or settlement of any Transaction Litigation and will not compromise, settle, come to an arrangement regarding or agree to compromise, settle or come to an arrangement regarding any Transaction Litigation or consent to the same, without the prior written consent of Parent (which consent will not be unreasonably withheld, conditioned or delayed). In connection with any Transaction Litigation and the Parties' performance of their obligations under this Section 6.13, the Parties will enter into a customary common interest or joint defense agreement or implement such other techniques as reasonably required to preserve any attorney-client privilege or other applicable legal privilege; except that the Company will not be required to provide information if doing so, in the opinion of the Company's legal counsel, would cause the loss of any attorney-client privilege or other applicable legal privilege; except that, if any information is withheld pursuant to the foregoing exception, the Company will inform Parent as to the general nature of what is being withheld and the Parties will use reasonable best efforts to enable the Company to provide such information without causing the loss of any attorney-client or other applicable legal privilege.

Section 6.14 Publicity. The initial press release with respect to the execution of this Agreement will be a joint press release to be reasonably agreed upon by Parent and the Company. Following such initial press release, none of the Company, Parent or Merger Sub will, and neither the Company nor Parent will permit any of its Subsidiaries to, issue or cause the publication of any press release or similar public announcement with respect to, or otherwise make any public statement concerning, the Transactions without the prior consent (which consent will not be unreasonably withheld, conditioned or delayed) of Parent, in the case of a proposed announcement or statement by the Company, or the Company, in the case of a proposed announcement or statement by Parent or Merger Sub; except that either Party may, without the prior consent of the other Party (but after prior consultation with the other Party to the extent practicable under the circumstances) issue or cause the publication of any press release or other public announcement to the extent such Party may reasonably conclude may be required by applicable Law or by the rules and regulations of the NYSE. The restrictions set forth in this Section 6.14 will not apply to any release or public statement (a) made or proposed to be made by the Company in connection with an Alternative Proposal or a Superior Proposal or any action taken pursuant thereto or (b) in connection with any dispute between the Parties regarding this Agreement or the Transactions; except that the foregoing will not limit the ability of any Party hereto to make internal announcements to their respective employees and other shareholders that are not inconsistent in any material respects with the prior public disclosures regarding the Transactions.

Section 6.15 Takeover Laws. If any Takeover Law is or may become applicable to the Transactions, the Company, including the Company Board, will grant such approvals and take such actions as are necessary so that the Transactions may be consummated as promptly as practicable on the terms contemplated by this Agreement and will otherwise act to irrevocably eliminate the effects of such Takeover Law on the Merger.

ARTICLE VII

CLOSING CONDITIONS

Section 7.1 Conditions to Each Party's Obligation to Effect the Merger. The respective obligations of the Parties to effect the Merger will be subject to the satisfaction at or prior to the Effective Time of the following conditions:

(a) Shareholder Approval. The Company Shareholder Approval has been obtained.

(b) Regulatory Consents. The waiting period applicable to the consummation of the Merger under the HSR Act has expired or has been terminated; each of the State Approvals, the FCC Approval and any other approval which Parent and the Company mutually agree is required in connection with the Merger, in each case, has been obtained at or prior to the Effective Time and such approvals have become Final Orders (the "Regulatory Approvals").

(c) No Orders or Restraints; Illegality. No Order preventing the consummation of the Transactions will be in effect. No statute, rule, regulation, or Order will have been enacted, entered, promulgated or enforced by any Governmental Entity that prohibits or makes illegal consummation of the Merger.

Section 7.2 Conditions to Obligations of Parent and Merger Sub. The obligation of Parent and Merger Sub to effect the Merger is also subject to the satisfaction, or waiver by Parent, on behalf of itself and Merger Sub, at or prior to the Effective Time, of the following conditions:

(a) Representations and Warranties. The representations and warranties of the Company set forth in this Agreement will be true and correct as of the date of this Agreement and as of the Effective Time as though made on and as of the Effective Time (except that representations and warranties that by their terms speak specifically as of the date of this Agreement or another date will be true and correct as of such date), except that this condition will be deemed satisfied unless all inaccuracies in such representations and warranties in the aggregate constitute a Company Material Adverse Effect at the Closing Date (ignoring solely for purposes of this proviso any reference to Company Material Adverse Effect or other materiality qualifiers contained in such representations and warranties). The representations and warranties of the Company set forth in Sections 3.2(a), 3.2(b), 3.2(c), 3.2(d) and 3.3(a) will be true and correct in all material respects as of the date of this Agreement and as of the Effective Time as though made on and as of the Effective Time (except that representations and warranties that by their terms speak specifically as of the date of this Agreement or another date will be true and correct as of such date). Parent will have received a certificate signed on behalf of the Company by the Chief Executive Officer or the Chief Financial Officer of the Company to the foregoing effect.

(b) Performance of Obligations of the Company. The Company will have performed in all material respects all agreements, obligations and covenants required to be performed by it under this Agreement at or prior to the Closing Date, and Parent will have received a certificate signed on behalf of the Company by the Chief Executive Officer or the Chief Financial Officer of the Company to such effect.

(c) Company Material Adverse Effect. There will not have occurred at any time after the date of this Agreement any Company Material Adverse Effect.

Section 7.3 Conditions to Obligations of the Company. The obligation of the Company to effect the Merger is also subject to the satisfaction or waiver by the Company at or prior to the Effective Time of the following conditions:

(a) Representations and Warranties. The representations and warranties of Parent and Merger Sub set forth in this Agreement will be true and correct as of the date of this Agreement and as of the Effective Time as though made on and as of the Effective Time (except that representations and warranties that by their terms speak specifically as of the date of this Agreement or another date will be true and correct as of such date), except that this condition will be deemed satisfied unless all inaccuracies in such representations and warranties in the aggregate constitute a Parent Material Adverse Effect at the Closing Date (ignoring solely for purposes of this exception any reference to Parent Material Adverse Effect or other materiality qualifiers contained in such representations and warranties), and the Company will have received a certificate signed on behalf of Parent and Merger Sub by the Chief Executive Officer or the Chief Financial Officer of Parent to the foregoing effect.

(b) Performance of Obligations of Parent. Parent and Merger Sub will have performed in all material respects all agreements, obligations and covenants required to be performed by them under this Agreement at or prior to the Closing Date, and the Company will have received a certificate signed on behalf of Parent and Merger Sub by the Chief Executive Officer or the Chief Financial Officer of Parent to such effect.

Section 7.4 Frustration of Closing Conditions. No Party may rely on the failure of any condition set forth in Section 7.1, Section 7.2, or Section 7.3, as the case may be, to be satisfied, if such Party's failure to perform any material obligation required to be performed by it has been the primary cause of, or primarily results in, such failure.

ARTICLE VIII

TERMINATION AND AMENDMENT

Section 8.1 Termination. This Agreement may be terminated and the Transactions abandoned at any time prior to the Effective Time:

(a) by the mutual written consent of the Company and Parent duly authorized by each of the Company Board and the Parent Board, respectively;

(b) by either of the Company or Parent:

(i) by written notice to the other Party at any time after the Outside Date, if the Closing has not been consummated on or before the Outside Date; except that, if on the Outside Date the condition set forth in Section 7.1(b) or the condition set forth in Section 7.1(c) (to the extent related to seeking the Regulatory Approvals) is not satisfied but all of the other conditions to Closing have been satisfied or waived (other than those conditions that by their nature are to be satisfied at the Closing) and if not satisfied, the condition set forth in Section 7.1(b) remains capable of being satisfied, then the Outside Date may be extended until February 23, 2017 at the election of Parent or the Company by written notice to the other Party at or before 11:59 p.m. Atlanta, Georgia time on the Outside Date; and except that the right to terminate this Agreement under this Section 8.1(b)(i) will not be available (x) to a Party if the inability to satisfy such conditions was due to the failure of such Party to perform any of its obligations under this Agreement or (y) to a Party if the other Party has filed (and is then pursuing) an action seeking specific performance as permitted by Section 9.12;

(ii) if any Order having the effect set forth in Section 7.1(c) is in effect and has become final and nonappealable; or

(iii) if the Company Shareholder Approval is not obtained at the duly held Company Shareholders Meeting, including any adjournments thereof;

(c) by Parent:

(i) if the Company has breached any of its representations or warranties set forth in this Agreement (or if any such representations or warranties fail to be true) or the Company has failed to perform any of its covenants or agreements set forth in this Agreement, which breach or failure (A) would (if it occurred or was continuing as of the Closing Date) give rise to the failure of a condition set forth in Section 7.2(a) or Section 7.2(b) and (B) is incapable of being cured, or is not cured by the Company by the earlier of (x) the Outside Date and (y) 30 days following receipt of written notice from Parent of such breach or failure; or

(ii) prior to receipt of the Company Shareholder Approval, if the Company Board has made a Change of Recommendation (whether or not in compliance with Section 6.9(c)); or

(d) by the Company:

(i) if either Parent or Merger Sub has breached any of its respective representations or warranties set forth in this Agreement (or if any such representations or warranties fail to be true) or either Parent or Merger Sub has failed to perform its respective covenants or agreements set forth in this Agreement, which breach or failure (A) would (if it occurred or was continuing as of the Closing Date) give rise to the failure of a condition set forth in Section 7.3(a) or Section 7.3(b) and (B) is incapable of being cured, or is not cured, by Parent by the earlier of (1) the Outside Date and (2) 30 days following receipt of written notice from the Company of such breach or failure; or

(ii) prior to receipt of the Company Shareholder Approval, if the Company Board has made a Change of Recommendation and the Company has complied in all material respects with Section 6.9; provided that (A) prior to, and as a condition of, any termination of this Agreement by the Company pursuant to this Section 8.1(d)(ii), the Company will have paid the Company Termination Fee to Parent pursuant to Section 8.2(b) and (B) any termination notice under Section

8.2(a) with respect to termination under this Section 8.1(d)(ii) may be given simultaneously with the Change of Recommendation.

Section 8.2 Effect of Termination.

(a) Generally. In the event of the termination of this Agreement as provided in Section 8.1, written notice thereof will be given to the other Party or Parties, specifying the provision of this Agreement pursuant to which such termination is made, and this Agreement will become null and void (other than the provisions of this Section 8.2 and the provisions in Article IX, all of which will survive termination of this Agreement). Except as provided in Section 8.2(b), upon termination pursuant to this Article VIII, there will be no liability on the part of Parent, Merger Sub, the Company or their respective directors, managers, officers and Affiliates (whether or not the terminating Party), except that, upon the termination of this Agreement, nothing will be deemed to release any Party from any liability to any other Party for any intentional breach by such Party of this Agreement prior to such termination.

(b) Company Termination Fee.

(i) In the event that this Agreement is terminated (A) by Parent pursuant to Section 8.1(c)(ii), (B) by the Company or Parent pursuant to Section 8.1(b)(i) and the Company Shareholders Meeting was not held or completed prior to termination at a time when this Agreement was terminable by Parent pursuant to (1) Section 8.1(c)(i) (if the failure to hold or complete the Company Shareholders Meeting was due to the Company's failure to perform any covenant or agreement set forth in this Agreement (but not if due to any breach or failure to be true of any of the representations or warranties of the Company set forth in this Agreement)) or (2) Section 8.1(c)(ii) or (C) by the Company or Parent pursuant to Section 8.1(b)(iii) at a time when this Agreement was terminable by Parent pursuant to (1) Section 8.1(c)(i) (if the failure to obtain the Company Shareholder Approval was due to the Company's failure to perform any covenant or agreement set forth in this Agreement (but not if due to any breach or failure to be true of any of the representations or warranties of the Company set forth in this Agreement)) or (2) Section 8.1(c)(ii), then the Company will pay to Parent a termination fee of $201,000,000 (the "Company Termination Fee") promptly (but in no event later than two Business Days) after such termination, by wire transfer of immediately available funds.

(ii) In the event that this Agreement is terminated by the Company pursuant to Section 8.1(d)(ii), then the Company will pay Parent the Company Termination Fee prior to, and as a condition of, such termination.

(iii) In the event that this Agreement is terminated (A) (1) by Parent pursuant to Section 8.1(c)(i), if due to the Company's failure to perform any covenant or agreement set forth in this Agreement (but not if due to any breach or failure to be true of any of the representations or warranties of the Company set forth in this Agreement), and prior to such termination an

Alternative Proposal has been made to the Company or has otherwise been publicly announced, or a Person will have publicly announced an intention to make an Alternative Proposal, (2) by Parent or the Company pursuant to Section 8.1(b)(i) at a time when (x) this Agreement was terminable by Parent pursuant to Section 8.1(c)(i), if due to the Company's failure to perform any covenant or agreement set forth in this Agreement (but not if due to any breach or failure to be true of any of the representations or warranties of the Company set forth in this Agreement) or (y) the Company Shareholder Approval was not obtained due to the Company Shareholders Meeting not being held or completed, and in each case prior to such termination an Alternative Proposal has been made to the Company or has otherwise been publicly announced, or a Person will have publicly announced an intention to make an Alternative Proposal, or (3) by Parent or the Company pursuant to Section 8.1(b)(iii), and prior to the date of the Company Shareholders Meeting an Alternative Proposal has been made to the Company or has otherwise been publicly announced, or a Person will have publicly announced an intention to make an Alternative Proposal, and (B) within nine months after any such termination (1) the Company or any of its Affiliates has entered into an Alternative Acquisition Agreement or (2) any Alternative Proposal has been consummated, then the Company will pay the Company Termination Fee to Parent upon the earlier of (x) the consummation of such Alternative Proposal and (y) entry into such Alternative Acquisition Agreement, by wire transfer of immediately available funds; except that the Company Termination Fee payable pursuant to this Section 8.2(b)(iii) will be reduced by the Expense Reimbursement, if any, actually paid to Parent pursuant to Section 8.2(c). For purposes of this Section 8.2(b)(iii) (including for purposes of the definition of Alternative Acquisition Agreement), references to "10% or more" in the definition of Alternative Proposal will be deemed to be references to "more than 50%."

(c) Expense Reimbursement. In the event that this Agreement is terminated, by Parent or the Company pursuant to Section 8.1(b)(iii) (but not to the extent Section 8.2(b)(i)(C) is applicable), then the Company will pay to Parent its and its Affiliates' reasonable out-of-pocket costs, fees and expenses incurred in connection with their investigation, consideration, documentation, diligence and negotiation of this Agreement and the Transactions (including the Financing), including all fees and expenses of Parent's and its Affiliates' Representatives (the "Expense Reimbursement"), by wire transfer of immediately available funds; except that the Expense Reimbursement will not exceed $5,000,000 and the Company will not be obligated to reimburse Parent for any internal cost allocations or charges among its Affiliates. Provided that the Company has not breached its obligations under this Agreement in any material respect, the Expense Reimbursement will be the sole and exclusive remedy of Parent or Merger Sub against the Company for a termination of the Agreement in accordance with Section 8.1(b)(iii), other than the payment of the Company Termination Fee to the extent it is or otherwise becomes payable pursuant to Section 8.2(b). In the event the Expense Reimbursement is paid and a Company Termination Fee is thereafter payable pursuant to Section 8.2(b), the Company

Termination Fee otherwise payable will be reduced by the amount of the Expense Reimbursement.

(d) Collection Fees and Expenses. Each Party acknowledges that the agreements contained in this Section 8.2 are an integral part of the Transactions, and that, without these agreements, no Party would enter into this Agreement. Accordingly, if the Company fails to promptly pay any amount due under this Section 8.2, and, in order to obtain such payment, Parent commences an Action that results in an Order against the Company, the Company will pay to Parent the costs and expenses (including attorney's fees and expenses) in connection with such Action and will pay interest on the amount payable pursuant to such Order, compounded quarterly, at the prime lending rate prevailing during such period as published in *The Wall Street Journal,* calculated on a daily basis from the date such amounts were required to be paid (but for such Action) until the date of actual payment. In no event will the Company be obligated to pay more than one Company Termination Fee pursuant to this Section 8.2.

(e) Sole and Exclusive Remedy. Provided that the Company has not wilfully breached in any material respect its obligations under (i) Section 6.9 or (ii) (A) Section 6.2(a) or 6.2(c) and (B) such breach results in a failure to hold or complete the Company Shareholders Meeting or a failure to file or mail the Proxy Statement, in the event that the Company Termination Fee is paid by the Company to Parent in accordance with this Section 8.2, such payment will be the sole and exclusive remedy at law of Parent and Merger Sub against the Company for any and all losses, claims, damages, liabilities, costs, fees, expenses (including reasonable attorney's fees and disbursements), judgments, inquiries and fines suffered as a result of any breach of any representation, warranty, covenant or agreement in this Agreement by the Company; except that the foregoing will not impair the rights of Parent to obtain injunctive relief pursuant to Section 9.12 prior to any termination of this Agreement. Solely for purposes of this Section 8.2(e), a "wilful" breach will be deemed to have occurred if the Company took or failed to take action with knowledge that such action or inaction constituted a breach of such obligation.

ARTICLE IX

GENERAL PROVISIONS

Section 9.1 Nonsurvival of Representations, Warranties and Covenants. None of the representations, warranties and covenants set forth in this Agreement or in any instrument delivered pursuant to this Agreement will survive the Effective Time, except for Section 6.5, Article I and Article II and for those other covenants and agreements contained in this Agreement that by their terms apply or are to be performed in whole or in part after the Effective Time.

Section 9.2 Notices. All notices and other communications in connection with this Agreement will be in writing and will be deemed given when delivered personally, sent via electronic mail, mailed by registered or certified mail or delivered by an express courier to the Parties at the following addresses (or at such other address for a Party as will be specified by like notice):

(a) if to the Company, to:

AGL Resources Inc.
Ten Peachtree Place, N.E.
Atlanta, Georgia 30309
Attention: Paul R. Shlanta
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer
Email: pshlanta@aglresources.com

with a copy to (which will not constitute notice):

Cravath, Swaine & Moore LLP
Worldwide Plaza
825 Eighth Avenue
New York, New York 10019
Attention: Richard Hall
Andrew R. Thompson
Email: rhall@cravath.com
athompson@cravath.com

(b) if to Parent or Merger Sub, to:

The Southern Company
30 Ivan Allen Jr. Boulevard, N.W.
Atlanta, Georgia 30308
Attention: James Y. Kerr II
Executive Vice President, General Counsel and Chief Compliance Officer
Email: jykerr@southernco.com

with a copy to (which will not constitute notice):

Jones Day
1420 Peachtree Street, N.E.
Suite 800
Atlanta, Georgia 30309-3053
Attention: William B. Rowland
Bryan E. Davis
Lizanne Thomas
Email: wbrowland@jonesday.com
bedavis@jonesday.com
lthomas@jonesday.com

Section 9.3 Interpretation.

(a) When a reference is made in this Agreement to Articles, Sections or Disclosure Letters, such reference will be to an Article or Section of or Disclosure Letters to this Agreement unless otherwise indicated. The table of contents and headings contained in this Agreement are for reference purposes only and will not affect in any way the meaning or interpretation of this Agreement. Whenever the words “include,” “includes” or “including” are used in this Agreement, they will be deemed to be followed by the words “without limitation.” Unless the context otherwise requires, (i) “or” is disjunctive but not exclusive, (ii) words in the singular include the plural and vice versa, and (iii) the use in this Agreement of a pronoun in reference to a Party hereto includes the masculine, feminine or neuter, as the context may require. The Company Disclosure Letter and the Parent Disclosure Letter as well as all other schedules hereto, will be deemed part of this Agreement and included in any reference to this Agreement. The representations and warranties of Parent and the Company are made and given, and the covenants are agreed to, subject to the disclosures and exceptions set forth in the Company Disclosure Letter and the Parent Disclosure Letter. In no event will the listing of any matter in the Company Disclosure Letter and the Parent Disclosure Letter be deemed or interpreted to expand the scope the respective Party’s representations, warranties or covenants set forth in this Agreement. All attachments to the Company Disclosure Letter and the Parent Disclosure Letter are incorporated by reference into the Company Disclosure Letter and the Parent Disclosure Letter, respectively, in which they are directly or indirectly referenced. Notwithstanding anything in this Agreement to the contrary, the mere inclusion of an item therein as an exception to a representation or warranty will not be deemed an admission that such item represents a material exception or material fact, event or circumstance or that such item has had or would, individually or in the aggregate, have a Company Material Adverse Effect or Parent Material Adverse Effect, as the case may be.

(b) The Parties have participated jointly in negotiating and drafting this Agreement. In the event that an ambiguity or a question of intent or interpretation arises, this Agreement will be construed as if drafted jointly by the Parties, and no presumption or burden of proof will arise favoring or disfavoring any Party by virtue of the authorship of any provision of this Agreement.

Section 9.4 Counterparts. This Agreement may be executed in two or more counterparts, all of which will be considered one and the same agreement and will become effective when counterparts have been signed by each of the Parties and delivered to the other Party, it being understood that each Party need not sign the same counterpart.

Section 9.5 Entire Agreement; Third Party Beneficiaries. This Agreement (including the documents and the instruments referred to in this Agreement), together with the Company Disclosure Letter, the Parent Disclosure Letter and the Confidentiality Agreement, (a) constitutes the entire agreement and supersedes all prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement, (b) is not intended to confer on any Person, other than the

Parties hereto and their respective successors and permitted assigns, any rights or remedies hereunder, except for (i) the rights of the Company's shareholders and holders of Company Stock Awards to receive the Merger Consideration and related consideration, respectively, at the Effective Time, (ii) as provided in Section 6.5 (which is intended for the benefit of the Indemnified Parties, each of whom will be a third party beneficiary of Section 6.5) and (iii) the Financing Sources and their respective successors, legal representatives and permitted assigns (each of which will be a third party beneficiary with respect to their respective rights under this Section 9.5 and Sections 9.6, 9.9 and 9.14).

Section 9.6 Amendment. Subject to compliance with applicable Law, this Agreement may be amended by the Company and Parent (on behalf of itself and Merger Sub), at any time prior to the Effective Time by an instrument in writing signed on behalf of each of the Parties. Notwithstanding anything to the contrary contained herein, this Section 9.6 and Sections 9.5, 9.9 and 9.14 may not be amended, supplemented, waived or otherwise modified in a manner adverse to the Financing Sources without the prior written consent of the Financing Sources.

Section 9.7 Extension; Waiver. At any time prior to the Effective Time, the Company and Parent (on behalf of itself and Merger Sub), by action taken or authorized by the Company Board and the Parent Board, may, to the extent legally allowed, (a) extend the time for the performance of any of the obligations or other acts of the other Party, (b) waive any inaccuracies in the representations and warranties contained in this Agreement, and (c) waive compliance with any of the obligations, covenants, agreements or conditions contained in this Agreement. Any agreement on the part of a Party to any such extension or waiver will be valid only if set forth in a written instrument signed on behalf of such Party, but such extension or waiver or failure to insist on strict compliance with an obligation, covenant, agreement or condition will not operate as a waiver of, or estoppel with respect to, any subsequent or other failure.

Section 9.8 Governing Law. This Agreement will be governed and construed in accordance with the internal Laws of the State of Georgia applicable to Contracts made and wholly performed within such state, without regard to any applicable conflict of laws principles (whether of the State of Georgia or any other jurisdiction).

Section 9.9 Jurisdiction.

(a) Each of the Parties hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of the courts of the State of Georgia located in the County of Fulton and of the United States District Court for the Northern District of Georgia, Atlanta Division (together, the "Chosen Courts"), in any action or proceeding arising out of or relating to this Agreement or the Transactions or for recognition or enforcement of any judgment relating thereto, and each of the Parties hereby irrevocably and unconditionally (i) agrees not to commence any such action or proceeding except in the Chosen Courts, (ii) agrees that any claim in respect of any such action or proceeding may be heard and determined in the Chosen Courts, and any appellate court hearing actions or proceedings therefrom, (iii) waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any such action or proceeding in the Chosen Courts, and (iv) waives, to the fullest extent it may legally and effectively do so, the defense of an inconvenient forum to the maintenance of such action or proceeding in the Chosen Courts. Each of the Parties hereto agrees that a final judgment in any such action or proceeding will be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by Law. Notwithstanding the foregoing, each of the Parties agrees that it will not, and will not permit its Affiliates to, bring or support any action, cause of action, claim, cross-claim or third-party claim of any kind or description, whether in law or in equity and whether in contract or in tort or otherwise, against the Financing Sources in any way related to this Agreement or any of the Transactions (including any dispute arising out of or relating to the Financing or the performance thereof) in any forum other than the United States District Court for the Southern District of New York or the Supreme Court of the State of New York, New York County, located in the Borough of Manhattan or, in either case, any appellate court thereof.

(b) EACH PARTY HERETO ACKNOWLEDGES AND AGREES THAT ANY CONTROVERSY WHICH MAY ARISE UNDER THIS AGREEMENT IS LIKELY TO INVOLVE COMPLICATED AND DIFFICULT ISSUES, AND THEREFORE IT HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS OR THE FINANCING, INCLUDING ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THE DEBT COMMITMENT LETTERS OR THE PERFORMANCE THEREOF. EACH PARTY CERTIFIES AND ACKNOWLEDGES THAT (i) NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE EITHER OF SUCH WAIVERS, (ii) IT UNDERSTANDS AND HAS CONSIDERED THE IMPLICATIONS OF SUCH WAIVERS, (iii) IT MAKES SUCH WAIVERS VOLUNTARILY, AND (iv) IT HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 9.9(B).

Section 9.10 Fees and Expenses. Except as expressly provided in this Agreement, whether or not the Merger is consummated, all fees and expenses incurred in connection with this Agreement and the Transactions will be paid by the Party incurring or required to incur such fees or expenses.

Section 9.11 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder will be assigned by any of the Parties hereto (whether by operation of law or otherwise) without the prior written consent of the other Parties and any attempt to do so will be null and void. Subject to the preceding sentence, this Agreement will be binding upon, inure to the benefit of and be enforceable by the Parties hereto and their respective permitted successors and assigns.

Section 9.12 Specific Performance. The Parties hereto agree that immediate, extensive and irreparable damage, for which monetary damages would not be an adequate remedy, would occur in the event that the Parties hereto do not perform their obligations under the provisions of this Agreement in accordance with its specified terms or otherwise breach such provisions. Accordingly, the Parties acknowledge and agree that the Parties will be entitled, in addition to any other remedy to which they are entitled at law or in equity, to an injunction or injunctions, specific performance or other equitable relief to prevent breaches of this Agreement and to enforce specifically the terms and provisions hereof (including the obligation of the Parties hereto to consummate the Merger and the obligation of Parent and Merger Sub to pay, and the Company's shareholders' right to receive, the Merger Consideration payable to them pursuant to the Merger, in each case in accordance with the terms and subject to the conditions of this Agreement) in the Chosen Courts without proof of damages or otherwise, and that such explicit rights of specific enforcement are an integral part of the Transactions and, without such rights, neither the Company nor Parent would have entered into this Agreement. Each of the Parties hereto agrees that it will not oppose the granting of an injunction, specific performance and other equitable relief on the basis that the other Parties hereto have an adequate remedy at law or an award of specific performance is not an appropriate remedy for any reason at law or in equity. The Parties hereto acknowledge and agree that any Party seeking an injunction or injunctions to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement will not be required to provide any bond or other security in connection with any such order or injunction.

Section 9.13 Severability. If any term, provision, covenant or restriction of this Agreement is held by a court of competent jurisdiction or other authority to be invalid, void, unenforceable, such term, provision, covenant or restriction will be deemed to be modified to the extent necessary to render it valid, effective and enforceable, and the remainder of the terms, provisions, covenants and restrictions of this Agreement will remain in full force and effect and will in no way be affected, impaired or invalidated.

Section 9.14 Liability of Financing Sources. Notwithstanding anything to the contrary contained herein, the Company agrees that it will not have any rights or claims against any Financing Source (in their capacity as such) in connection with this Agreement, the Financing or the transactions contemplated hereby or thereby, and no Financing Source will have any rights or claims against the Company or any of its Affiliates or Representatives in connection with this Agreement, the Financing or the transactions contemplated hereby or thereby, whether at law or in equity, in contract tort or otherwise. In addition, in no event will any Financing Source be liable for consequential, special, exemplary, punitive or indirect damages (including any loss of profits, business or anticipated savings) or damages of a tortious nature, except to the extent paid in connection with a claim by a third party.

Section 9.15 Definitions. For the purposes of this Agreement:

"Action" has the meaning set forth in Section 3.8(a).

"Affiliate" means a Person that directly or indirectly, through one or more intermediaries, control, is controlled by, or is under common control with, the first-mentioned Person. For this purpose, "control" (including the terms "controlled by" and "under common control with") means the possession, directly or indirectly or as trustee or executor, of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of stock, by Contract or otherwise.

"Agreement" has the meaning set forth in the Preamble.

"Alternative Acquisition Agreement" has the meaning set forth in Section 6.9(a)(i)(B).

"Alternative Financing" means any financing from alternative sources in an amount, when taken together with other sources and all other Debt Commitment Letters, sufficient to consummate the Transactions with terms and conditions not materially less favorable, taken as a whole, to Parent, Merger Sub and the Company than the terms and conditions set forth in the applicable Financing Agreements.

"Alternative Proposal" means any proposal or offer made by a Person (other than Parent or Merger Sub) relating to (a) any direct or indirect acquisition or purchase, in a single transaction or a series of related transactions, of (i) 10% or more of the consolidated total assets of the Company and the Company Subsidiaries, taken as a whole, or (ii) 10% or more of any class of Company Capital Stock, (b) any tender offer or exchange offer that if consummated would result in any Person beneficially owning, directly or indirectly, 10% or more of any class of Company Capital Stock, (c) any merger, consolidation, exclusive license, business combination, joint venture, partnership, share exchange or other transaction involving the Company pursuant to which any Person or its holders of Equity Interests would beneficially own, directly or indirectly, 10% or more of any class of outstanding Company Capital Stock or the surviving entity resulting, directly or indirectly, from any such transaction or (d) concerning any recapitalization, liquidation, dissolution or any other similar transaction involving the Company or any of the Company Subsidiaries, in each case, other than the Transactions.

"Approval" has the meaning set forth in Section 3.10(b).

"Assumed Awards" has the meaning set forth in Section 2.3(d).

"Bona Fide Alternative Proposal" means an unsolicited written bona fide Alternative Proposal that was not received or obtained in violation of Section 6.9.

"Bonus Plans" has the meaning set forth in Section 6.4(e).

"Book-Entry Shares" has the meaning set forth in Section 1.5(a).

"Burdensome Effect" means any terms, conditions, liabilities, obligations, commitments or sanctions imposed upon or otherwise affecting, directly or indirectly, Parent, the Company or their respective Subsidiaries in any Order or consent of, or agreement with, a Governmental Entity with respect to the Transactions, including the Regulatory Approvals, that, individually or in the aggregate, (a) would reasonably be expected to have a material adverse effect on the condition (financial or otherwise), assets, liabilities, businesses or results of operations of Parent and the Company and their respective Subsidiaries, taken as whole, or (b) would require the Company or any Company Subsidiary or Parent or any Parent Subsidiary to sell, divest, "hold separate for sale" or otherwise dispose of, or enter into a voting trust, proxy or "hold separate for sale" Contract or similar Contract for (i) one or more Company Subsidiaries (or substantially all of the assets of such Company Subsidiaries) and the cost of shared services allocated to such Company Subsidiaries exceeded 25% of total costs for shared services that were allocated in the year ended December 31, 2014 as such allocations were disclosed to Parent prior to the date hereof by the Company or (ii) one or more Parent Subsidiaries (or substantially all of the assets of such Parent Subsidiaries) and the cost of shared services allocated to such Parent Subsidiaries exceeded 25% of total costs for shared services that were allocated in the year ended December 31, 2014 as such allocations were disclosed to the Company prior to the date hereof by Parent.

"Business Day" means a day other than a Saturday, a Sunday or another day on which commercial banking institutions in New York, New York are authorized or required by Law to be closed.

"CERCLA" means the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended.

"Certificate of Merger" has the meaning set forth in Section 1.3.

"Certificates" has the meaning set forth in Section 1.5(a).

"Change of Recommendation" has the meaning set forth in Section 6.9(b)(v).

"Chosen Courts" has the meaning set forth in Section 9.9(a).

"Claim" has the meaning set forth in Section 6.5(a).

"Closing" has the meaning set forth in Section 1.2.

"Closing Date" has the meaning set forth in Section 1.2.

"COBRA" means the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended, and as codified in Section 4980B of the Code and Section 601 et. seq. of ERISA.

"Code" means the Internal Revenue Code of 1986, as amended.

"Company" has the meaning set forth in the Preamble.

"Company Benefit Plans" has the meaning set forth in Section 3.10(a).

“Company Board” has the meaning set forth in the Recitals.

“Company Board Recommendation” has the meaning set forth in Section 6.2(c).

“Company Bylaws” has the meaning set forth in Section 3.1(b).

“Company Capital Stock” has the meaning set forth in Section 3.2(a).

“Company Charter” has the meaning set forth in Section 3.1(b).

“Company Common Stock” means the common stock of the Company, par value $5.00 per Share.

“Company Commonly Controlled Entity” has the meaning set forth in Section 3.10(d).

“Company Deferred Compensation Plan” means the Company’s Nonqualified Savings Plan and the Company’s Common Stock Equivalent Plan for Non-Employee Directors.

“Company Deferred Stock Unit” means any stock unit award credited to the account of any participant in any Company Deferred Compensation Plan that is payable in Shares or whose value is determined with reference to the value of Shares.

“Company Disclosure Letter” has the meaning set forth in the preamble to Article III.

“Company DRIP” means the AGL Resources Direct Stock Purchase and Dividend Reinvestment Plan.

“Company Employees” has the meaning set forth in Section 6.4(a).

“Company Equity Incentive Plans” means the Company’s Omnibus Performance Incentive Plan, as amended and restated, the Company’s Long-Term Incentive Plan, as amended and restated as of January 1, 2002 and the Company’s Non-Employee Directors Equity Compensation Plan, as amended and restated.

“Company ESPP” means the Company’s Amended and Restated Employee Stock Purchase Plan.

“Company Financial Statements” has the meaning set forth in Section 3.6(a).

“Company Intellectual Property” has the meaning set forth in Section 3.14(a).

“Company Leased Real Property” has the meaning set forth in Section 3.16.

“Company Material Adverse Effect” means any fact, occurrence, change, effect or circumstance, individually or in the aggregate with all other facts, occurrences, changes, effects and circumstances that: (a) has had, or would reasonably be expected to result in, a material adverse effect on the business, assets, liabilities, properties or results of operations or financial condition of the Company and the Company Subsidiaries, taken as a whole, or (b) would, or would reasonably be expected to, prevent or materially impair or delay the ability of the Company to perform its obligations under this Agreement or consummate the Transactions; except that with respect to clause (a), in no event will any of the following, either alone or in combination, constitute a "Company Material Adverse Effect" or be taken into account in determining whether a Company Material Adverse Effect has occurred or would reasonably be expected to occur: (i) conditions or effects that generally affect the industries in which the Company and the Company Subsidiaries operate; (ii) general economic, political, or regulatory effects or conditions affecting the geographies in which the Company and the Company Subsidiaries operate; (iii) effects resulting from changes affecting equity or debt market conditions in the United States; (iv) any effects or conditions resulting from an outbreak or escalation of hostilities, acts of terrorism, political instability or other national or international calamity, crisis or emergency, or any governmental or other response to any of the foregoing, in each case whether or not involving the United States; (v) any change in the market price for commodities; (vi) any hurricane, earthquake, flood or other natural disasters or acts of God; (vii) any change resulting from weather conditions or customer use patterns; (viii) effects arising from changes in Laws or accounting principles (including GAAP) after the date hereof; (ix) effects relating to or arising from the announcement of the execution of this Agreement or the Transactions; (x) any Transaction Litigation; (xi) actions taken pursuant to this Agreement or at the request of Parent; or (xii) changes in the market price or trading volume of Company Common Stock or any failure to meet internal or published projections, forecasts or revenue or earnings predictions for any period (it being understood that the facts, occurrences, changes, effects or circumstances giving rise or contributing to any such change or failure will be taken into account in determining whether a Company Material Adverse Effect has occurred or would reasonably be expected to occur); except that the matters referred to in clauses (i) through (ix) above will be taken into account in determining whether a Company Material Adverse Effect has occurred or would reasonably be expected to occur to the extent such matters adversely affect the Company and the Company Subsidiaries in a materially disproportionate manner relative to other participants in the industries in which the Company and the Company Subsidiaries operate.

"Company Material Contract" has the meaning set forth in Section 3.13(a).

"Company Non-Solicit Parties" has the meaning set forth in Section 6.9(a)(i).

"Company Owned Real Property" has the meaning set forth in Section 3.16.

"Company PSU" has the meaning set forth in Section 2.3(d).

"Company Reports" has the meaning set forth in Section 3.5(a).

"Company Restricted Share" has the meaning set forth in Section 2.3(b).

"Company RSU" has the meaning set forth in Section 2.3(c).

"Company Shareholder Approval" has the meaning set forth in Section 3.3(a).

"Company Shareholders Meeting" has the meaning set forth in Section 6.2(c).

"Company Stock Awards" has the meaning set forth in Section 2.3(g).

"Company Stock Option" has the meaning set forth in Section 2.3(a).

"Company Subsidiary" has the meaning set forth in Section 3.1(c).

"Company Termination Fee" has the meaning set forth in Section 8.2(b)(i).

"Company Trading Guidelines" has the meaning set forth in Section 3.17(a).

"Compliant" means the Required Information (a) is in a form sufficiently current to permit (i) a registration statement filed by the Company using such financial statements to be declared effective by the SEC and (ii) the Company's independent auditors to issue a customary comfort letter, including as to customary negative assurances and change period (in accordance with its normal practices and procedures) and (b) is, and remains until the consummation of the Closing, compliant in all material respects with all requirements of Regulation S-K and Regulation S-X under the Securities Act (excluding information required by Regulation S-X Rule 3-10).

"Confidentiality Agreement" has the meaning set forth in Section 6.3(b).

"Continuation Period" has the meaning set forth in Section 6.4(a).

"Contracts" means any contracts, agreements, licenses (or sublicenses), notes, bonds, mortgages, indentures, commitments, leases (or subleases) or other instruments or obligations, whether written or oral.

"D&O Insurance" has the meaning set forth in Section 6.5(b).

"Debt Commitment Letters" means the commitment letters delivered by the Financing Sources with respect to certain debt facilities, the proceeds of which, among other uses, will be used by Parent to fund the payment of a portion of the Merger Consideration, including any commitment letters with respect to an Alternative Financing.

"Dissenting Shares" has the meaning set forth in Section 2.5.

"Dissenting Shareholder" has the meaning set forth in Section 2.5.

"DIST-CO" has the meaning set forth in Section 3.19(c).

"Dodd-Frank Act" has the meaning set forth in Section 3.17(b).

“DTC” has the meaning set forth in Section 2.1(b)(i).

“Effective Time” has the meaning set forth in Section 1.3.

“Employee” means any employee or former employee of the Company or any Company Subsidiary, as applicable.

“Environment” means soil, soil vapor, surface water, groundwater, land, sediment, surface or subsurface strata or ambient air.

“Environmental Authority” means any department, agency, or other body or component of any Governmental Entity that lawfully exercises jurisdiction under any Environmental Law.

“Environmental Authorization” means any Permit required under any Environmental Law.

“Environmental Law” means any Law relating to pollution (including greenhouse gases) or the protection of human health from environmental hazards or protection of the Environment, natural resources or occupational and worker health and safety (as such relates to exposure to Hazardous Substances).

“Environmental Liability” means any liability, or obligation of any kind or nature (whether arising from statutory or common law, sounding in tort or otherwise, whether asserted or unasserted, whether absolute or contingent, whether accrued or unaccrued, whether liquidated or unliquidated, and whether due or to become due) arising under any Environmental Law or Environmental Authorization.

“Equity Interest” means any share, capital stock, partnership, limited liability company, membership or similar interest in any Person.

“ERCC” has the meaning set forth in Section 3.19(d).

“ERISA” means the Employee Retirement Income Security Act of 1974, as amended.

“ESPP Purchase Right” means a right to purchase Shares issued under the Company ESPP.

“Exchange Act” has the meaning set forth in Section 3.4.

“Exchange Agent” has the meaning set forth in Section 2.1(a).

“Exchange Fund” has the meaning set forth in Section 2.1(a).

“Exchange Ratio” has the meaning set forth in Section 2.3(d).

“Expense Reimbursement” has the meaning set forth in Section 8.2(c).

"FCC" has the meaning set forth in Section 3.4.

"FCC Approval" has the meaning set forth in Section 3.4.

"FERC" means the Federal Energy Regulatory Commission.

"Final Order" means an action by the relevant Governmental Entity (i) that has not been reversed, stayed, enjoined, set aside, annulled or suspended and with respect to which any waiting period prescribed by Law before the Transactions may be consummated has expired, (ii) as to which all conditions to the consummation of the Transactions prescribed by Law have been satisfied and (iii) that does not require, contain or contemplate any undertaking, term, condition, liability, obligation, commitment or sanction that, individually or in the aggregate, constitutes or would reasonably be expected to constitute a Burdensome Effect.

"Financing" means the debt financing set forth in the Debt Commitment Letters, as such Debt Commitment Letters may be amended or replaced (including pursuant to any Alternative Financing).

"Financing Agreements" means the definitive agreements with respect to the Financing or Alternative Financing on terms and conditions contained in the Debt Commitment Letters or consistent in all material respects with the Debt Commitment Letters.

"Financing Source" means the Persons (including lenders, agents and arrangers) that have committed to provide or otherwise entered into agreements in connection with the Financing in connection with the Transactions, and any joinder agreements, indentures or credit agreements entered into pursuant thereto or relating thereto, together with their Affiliates and Representatives involved in the Financing and their respective successors and assigns.

"GAAP" means U.S. generally accepted accounting principles.

"GBCC" has the meaning set forth in Section 1.1.

"GERIC" has the meaning set forth in Section 3.19(b).

"Governmental Entity" has the meaning set forth in Section 3.4.

"Hazardous Substance" means any chemicals, pollutants, contaminants, toxins, wastes or substances defined or otherwise classified as or included in the definition of "hazardous substances," "hazardous wastes," "toxic substances," "contaminants," or "pollutants" regulated, in relevant form, quantity or concentration under any applicable Environmental Law, including asbestos or asbestos containing material, petroleum and its by-products, polychlorinated biphenyl and urea formaldehyde.

"HSR Act" has the meaning set forth in Section 3.4.

"Indemnified Parties" has the meaning set forth in Section 6.5(a).

"Intellectual Property" means all of the following anywhere in the world and all legal rights, title or interest in or under the following arising under Law: (a) all patents and applications for patents (including all invention disclosures) and all related reissues, reexaminations, divisions, renewals, extensions, provisionals, continuations and continuations in part, (b) all copyrights, copyright registrations, copyright applications and copyrightable works, (c) all trade dress and trade names, logos, Internet domain names, trademarks and service marks and registrations and applications therefor, including any intent to use applications, supplemental registrations and any renewals or extensions, all other indicia of commercial source or origin and all goodwill associated with any of the foregoing, (d) all computer software (including source and object code), (e) all inventions (whether patentable or unpatentable and whether or not reduced to practice) and know how, (f) trade secrets, confidential business information and other documentation, and other proprietary information (collectively, if and to the extent proprietary, held as confidential and protectable as a "trade secret" under applicable Law, "Trade Secrets"), (g) all databases and data collections and (h) all copies and tangible embodiments of any of the foregoing (in whatever form or medium).

"Intervening Event" means any material event, development or change in circumstances that first occurs, arises or becomes known to the Company or the Company Board after the date of this Agreement, to the extent that such event, development or change in circumstances was not reasonably foreseeable as of or prior to the date of this Agreement; except that in no event will (a) the receipt, existence or terms of an Alternative Proposal or any matter relating thereto or consequence thereof, (b) any action taken by the Parties pursuant to or in compliance with this Agreement, including any action taken in connection with seeking any Regulatory Approval, or (c) changes in the market price or trading volume of the Company Common Stock or the Company or any Company Subsidiary meeting or exceeding internal or published projections, forecasts or revenue or earnings predictions for any period (except that the underlying causes of such change or result will not be excluded by this clause (c), except to the extent such underlying causes are otherwise excluded pursuant to clause (a) or (b)) constitute an "Intervening Event" or be taken into account in determining whether an Intervening Event has occurred or would reasonably be expected to result.

"Intervening Event Negotiation Period" has the meaning set forth in Section 6.9(d)(ii).

"Intervening Event Notice" has the meaning set forth in Section 6.9(d)(ii).

"IRS" means Internal Revenue Service.

"knowledge," when used with respect to a Party, means the actual knowledge of the persons holding the following titles, or if there is none, people holding equivalent positions, at the applicable entity: Chief Executive Officer, President, Chief Financial Officer, Chief Operating Officer and General Counsel.

"Law" means any federal, state, local, municipal, foreign or other law, statute, constitution, principle of common law, resolution, ordinance, code, order, writ, edict, decree, rule, regulation, judgment, ruling, binding policy or guideline or requirement issued, enacted, adopted, promulgated, implemented or otherwise put into effect by or under the authority of any Governmental Entity.

"Liens" means any lien, mortgage, pledge, conditional or installment sale agreement, encumbrance, covenant, restriction, option, right of first refusal, easement, security interest, deed of trust, right-of-way, encroachment, community property interest or other claim or restriction of any nature, whether voluntarily incurred or arising by operation of Law.

"Measurement Date" has the meaning set forth in Section 3.2(a).

"Merger" has the meaning set forth in the Recitals.

"Merger Consideration" has the meaning set forth in Section 1.5(a).

"Merger Sub" has the meaning set forth in the Preamble.

"Merger Sub Bylaws" means the bylaws of Merger Sub.

"Negotiation Period" has the meaning set forth in Section 6.9(d)(i).

"Net Company Position" has the meaning set forth in Section 3.17(a).

"NGA" has the meaning set forth in Section 3.18(a).

"NYSE" means the New York Stock Exchange.

"Offering Documents" has the meaning set forth in Section 6.12(b).

"Offering Period" has the meaning set forth in Section 2.4.

"Order" means any judgment, order, decision, writ, injunction, decree, stipulation, award, ruling, or other finding or agency requirement of a Governmental Entity, or arbitration award.

"Outside Date" means August 23, 2016, or if extended to a later date pursuant to and in accordance with Section 8.1(b)(i), any such later date.

"Parent" has the meaning set forth in the Preamble.

"Parent Board" has the meaning set forth in the Recitals.

"Parent Common Stock" has the meaning set forth in Section 2.3(d).

"Parent Disclosure Letter" has the meaning set forth in the preamble to Article IV.

"Parent Material Adverse Effect" means any change, event, development, conditions, occurrence or effect that (a) has a material adverse effect on the ability of either Parent or Merger Sub to consummate the Transactions or perform their respective obligations under this Agreement or (b) would prevent or materially delay the consummation by Parent of the Transactions.

"Parent Reports" means, collectively, all registration statements, reports, forms, documents and proxy statements of Parent required to be filed with or furnished to the SEC since December 31, 2012, in each case including all exhibits and schedules thereto and all documents incorporated by reference therein, as such statements and reports may have been amended since the date of their filing.

"Parent Subsidiary" has the meaning set forth in Section 3.1(c).

"Parties" means collectively Parent, Merger Sub and the Company.

"Party" means any of Parent, Merger Sub or the Company.

"PCAOB" means the Public Company Accounting Oversight Board.

"Pension Plan" has the meaning set forth in Section 3.10(a).

"Permits" has the meaning set forth in Section 3.11(a).

"Permitted Lien" means (a) Liens in respect of any liabilities and obligations reflected in the financial statements of the Company and the Company Subsidiaries or Parent and the Parent Subsidiaries, as applicable, included in the Company Reports or Parent Reports, as applicable, (b) with respect to the owned real property and leased real property of the Company and the Company Subsidiaries or Parent and the Parent Subsidiaries, as applicable, (i) defects, exceptions, restrictions, rights of way, easements, covenants, encroachments and other imperfections of title and (ii) zoning, entitlement, land use, environmental regulations, and building restrictions, none of which impairs the uses of such property as currently used by the Company and the Company Subsidiaries or Parent and the Parent Subsidiaries, as applicable, such that such impairment, individually or in the aggregate materially impairs the use or operation of such property for their current use, (c) Liens for current Taxes not yet delinquent or being contested in good faith by appropriate proceedings and for which adequate reserves have been established in accordance with GAAP on the Company's or Parent's financial statements, as applicable, (d) mechanics', carriers', workmen's, repairmen's or other like Liens that arise or are incurred in the ordinary course of business; (e) licenses, options or other similar rights related to Intellectual Property granted in the ordinary course of business that do not materially impair the Company's or any Company Subsidiary's use of Company Intellectual Property; and (f) other customary Liens levied, assessed or imposed against, or in any manner affecting, the property of the Company and the Company Subsidiaries or Parent and the Parent Subsidiaries, as applicable, that, individually or in the aggregate, do not materially impair the use or operation of such property for their current use or have had a Company Material Adverse Effect.

“Person” means any individual (in any capacity) or legal entity, including a Governmental Entity.

“PPACA” means the Patient Protection and Affordable Care Act, as amended, and the guidance promulgated there under.

“Proxy Statement” has the meaning set forth in Section 3.4.

“PUHCA” has the meaning set forth in Section 3.18(a).

“Regulatory Agencies” means (a) any state or federal regulatory authority, (b) the SEC, and (c) any foreign regulatory authority.

“Regulatory Approvals” has the meaning set forth in Section 7.1(b).

“Release” means any release, spill, emission, leaking, pumping, injection, pouring, emptying, deposit, disposal, discharge, dispersal, leaching or migration into the Environment, or into or out of any real property owned, operated or leased by the Company or a Company Subsidiary.

“Representatives” means any officer, director, employee, investment banks, attorney or other advisor or representative of a Person.

“Required Information” means all customary financial and other information regarding the Company and its Subsidiaries as may be reasonably requested by Parent or Merger Sub, including financial statements prepared in accordance with GAAP, projections, audit reports, a draft of a customary comfort letter (including “negative assurance comfort”) with respect to such financial information by auditors of the Company which such auditors are prepared to issue upon completion of customary procedures letter and other information and data regarding the Company and the Subsidiaries of the type and form required by Regulation S-X and Regulation S-K under the Securities Act for registered offerings of securities on Form S-1, Form S-3 or Form S-4 (or any successor forms thereto) under the Securities Act, and of the type and form, and for the periods, customarily included in Offering Documents used to syndicate credit facilities of the type to be included in the Financing and in Offering Documents used in private placements of debt securities under Rule 144A of the Securities Act, to consummate the offerings or placements of any debt securities, in each case assuming that such syndication of credit facilities and offering(s) of debt securities were consummated at the same time during the Company’s fiscal year as such syndication and offering(s) of debt securities will be made (but in any event including such information with respect to the Company’s quarter ended September 30, 2015, and subsequent interim periods ending at least 45 days prior to the Closing Date, subsequent annual periods ending at least 75 days prior to Closing or otherwise), all of which will be Compliant.

“SEC” means the Securities and Exchange Commission.

“Securities Act” has the meaning set forth in Section 3.4.

"Share" has the meaning set forth in Section 1.5(a).

"SOX" has the meaning set forth in Section 3.5(a).

"State Approvals" has the meaning set forth in Section 3.4.

"State Commissions" has the meaning set forth in Section 3.4.

"Subsidiary" has the meaning set forth in Section 3.1(c).

"Superior Proposal" means a Bona Fide Alternative Proposal that the Company Board has determined in good faith, after consultation with its outside financial and legal advisors (taking into account the various legal, financial, regulatory (including the impact of any necessary regulatory approvals or antitrust Law on such Bona Fide Alternative Proposal) and other aspects of such Bona Fide Alternative Proposal), (a) is reasonably likely to be consummated in accordance with its terms and (b) if consummated, would result in a transaction more favorable to the Company's shareholders from a financial point of view than the Transactions (after taking into account any revisions to the terms of the Transactions proposed by Parent, pursuant to Section 6.9(d)(i)); except that for purposes of the definition of "Superior Proposal", the references to "10% or more" in the definition of Alternative Proposal will be deemed to be references to "more than 90%."

"Superior Proposal Notice" has the meaning set forth in Section 6.9(d)(i).

"Surviving Corporation" has the meaning set forth in Section 1.1.

"Takeover Laws" means any state takeover Law or other state Law that purports to limit or restrict business combinations or the ability to acquire or vote Company Common Stock, including any "business combination," "control share acquisition," "fair price," "moratorium" or other similar anti-takeover Law.

"Tax" or "Taxes" means any federal, state, local and foreign income, excise, gross receipts, gross income, ad valorem, profits, gains, property, capital, sales, transfer, use, value added, payroll, employment, unemployment, workers' compensation, severance, withholding, duties, intangibles, franchise, backup withholding and other taxes of any kind, charges, levies or like assessments, together with all penalties, and additions and interest thereto.

"Tax Return" includes all returns, reports, claims for refund and forms (including elections, attachments, declarations, disclosures, schedules, estimates, information returns and TD Form 90-22.1, and its successor form FinCEN Form 114) filed or required to be filed with any taxing authority, and including any amendment thereof.

"Trade Secrets" has the meaning set forth in the definition of Intellectual Property set forth in this Section 9.15.

"Transaction Litigation" has the meaning set forth in Section 6.13.

“Transactions” has the meaning set forth in Section 3.3(a).

“Treasury Regulations” means the regulations promulgated under the Code by the U.S. Department of the Treasury.

“Welfare Plan” has the meaning set forth in Section 3.10(a).

[Remainder of Page Intentionally Left Blank]

IN WITNESS WHEREOF, Parent, Merger Sub and the Company have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the date first above written.

THE SOUTHERN COMPANY

By: Thomas A. Fanning
Name: Thomas A. Fanning
Title: Chairman, President, and Chief Executive Officer

AMS CORP.

By: Thomas A. Fanning
Name: Thomas A. Fanning
Title: President and Chief Executive Officer

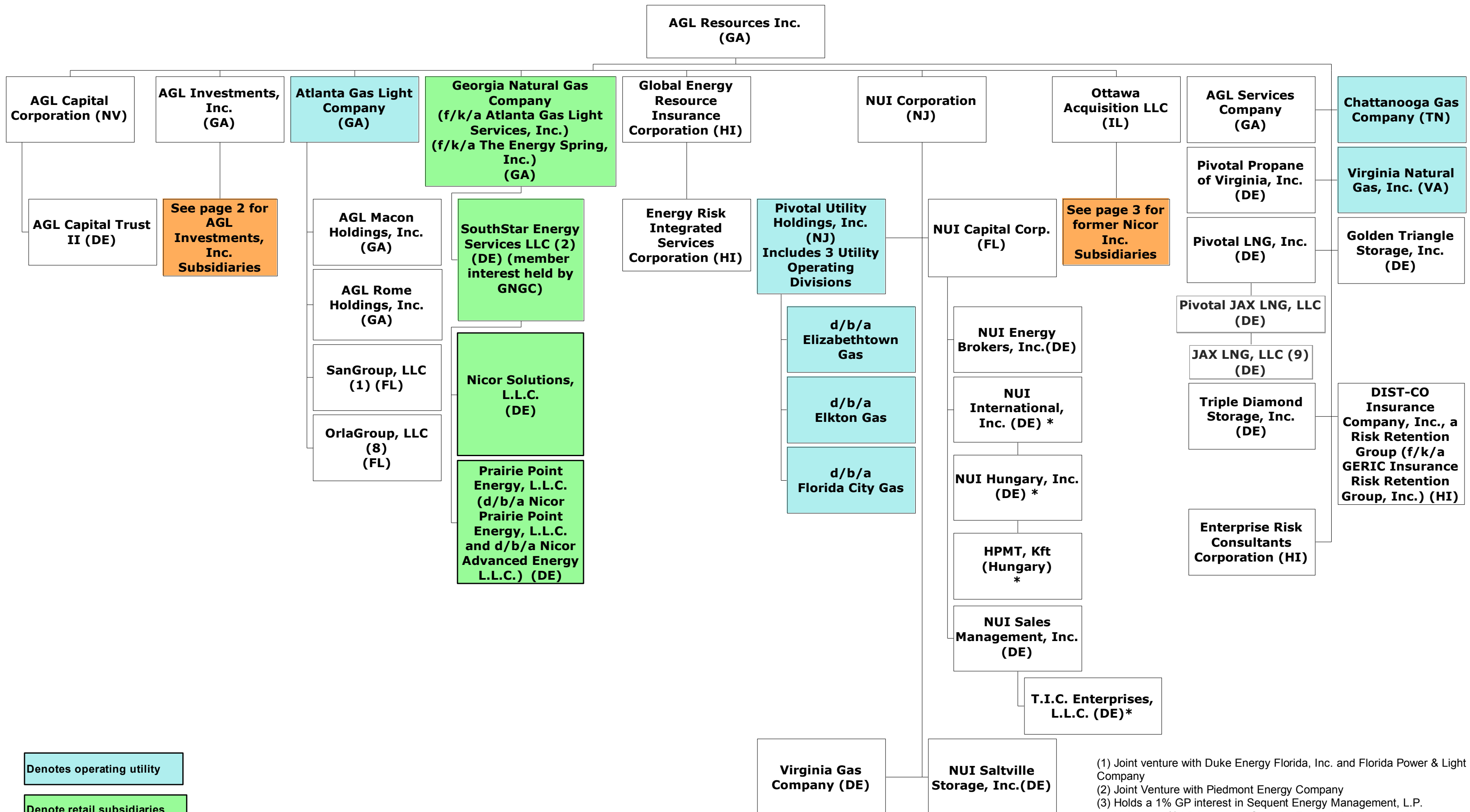
AGL RESOURCES INC.

By: ______________________
Name: John W. Somerhalder II
Title: Chairman, President and Chief Executive Officer

Exhibit 10

AGL Resources

Office of the Corporate Secretary
AGL Resources Inc. - Corporate Organizational Chart
August 6, 2015



Denotes operating utility

Denote retail subsidiaries

Denotes further subsidiaries

(1) Joint venture with Duke Energy Florida, Inc. and Florida Power & Light Company
(2) Joint Venture with Piedmont Energy Company
(3) Holds a 1% GP interest in Sequent Energy Management, L.P.
(4) Holds a 99% LP interest in Sequent Energy Management, L.P.
(5) Joint venture between Nicor Oil and Gas Corporation and APC Associates
(6) Joint venture between Nicor Horizon, Inc. and NGPL
(7) Doing business as Pivotal Home Solutions and other d/b/a names in various states
(8) Joint Venture with Duke Energy Florida, Inc.
(9) Joint Venture with Wespac

* Discontinued Operations

AGL Resources

Office of the Corporate Secretary
AGL Resources Inc. - Corporate Organizational Chart
August 6, 2015

- AGL Resources Inc. (GA)
  - AGL Investments, Inc. (GA)
    - AGL C&I Energy Services Inc. (DE)
      - Sequent Energy Services Inc. (DE) (f/k/a NUI Energy, Inc.)
    - AGL Energy Services, LLC (GA)
    - AGL Renewables, LLC (GA)
      - Renewco, LLC (DE)
      - Renewco - FCSL, LLC (DE)
      - Renewco-Meadow Branch, LLC (DE)
      - Renewco-Pine Ridge, LLC (DE)
      - Renewco-Richland Creek, LLC (DE)
    - AGL Southeast LNG, L.L.C. (GA)
      - Southeast LNG Distribution Company, LLC (DE)
    - Customer Care Services, Inc. (GA)
    - Georgia Gas Company (GA)
    - Magnolia Enterprise Holdings, Inc. (GA)
    - Organic Energy Solutions, LLC (GA)
      - PTC BioSolids, LLC (GA)
    - Pivotal Energy Services, Inc. (GA)
    - Pivotal Storage, Inc. (DE)
      - Pivotal Jefferson Island Storage & Hub, LLC. (DE)
        - Jefferson Island Storage & Hub, L.L.C. (DE)
    - Sequent Energy Canada Corp. (DE)
    - Sequent, LLC (3) (f/k/a AGL Energy Services, LLC) (GA)
      - Sequent Energy Management, L.P. (GA)
      - Sequent Holdings, LLC (4) (GA)
    - Southeastern LNG, Inc. (GA)
    - Trustees Investments, Inc. (GA)
    - Dogwood Enterprise Holdings, Inc. (GA)
    - Maple Enterprise Holdings, Inc. (GA)
    - Red Oak Enterprise Holdings, Inc. (GA)

(1) Joint venture with Duke Energy Florida, Inc. and Florida Power & Light Company
(2) Joint Venture with Piedmont Energy Company
(3) Holds a 1% GP interest in Sequent Energy Management, L.P.
(4) Holds a 99% LP interest in Sequent Energy Management, L.P.
(5) Joint venture between Nicor Oil and Gas Corporation and APC Associates
(6) Joint venture between Nicor Horizon, Inc. and NGPL
(7) Doing business as Pivotal Home Solutions and other d/b/a names in various states
(8) Joint Venture with Duke Energy Florida, Inc.
(9) Joint Venture with Wespac

* Discontinued Operations

AGL Resources

Office of the Corporate Secretary
AGL Resources Inc. - Corporate Organizational Chart
August 6, 2015

- **AGL Resources Inc. (GA)**
  - **Ottawa Acquisition LLC (IL)**
    - **Nicor Energy Ventures Company (DE)**
      - **Central Valley Gas Storage, L.L.C. (DE)**
      - **Nicor Enerchange, L.L.C. (DE)**
      - **Nicor Energy Services Company (7) (DE)**
        - **IBT Solutions, L.L.C. (DE)**
        - **Nicor Services LLC (DE)**
    - **Nicor Horizon, Inc. (DE)**
      - **Horizon Pipeline Company, L.L.C. (6) (DE)**
    - **Nicor Mining Inc. (DE)**
    - **Nicor National Inc. (DE)**
    - **Nicor Oil and Gas Corporation (DE)**
      - **Northern New England Energy Company (5) (ME)**
    - **Northern Illinois Gas Company (d/b/a Nicor Gas Company) (IL)**
      - **NI-Gas Exploration, Inc. (IL)**
    - **AGL Equipment Leasing Inc. (DE)**
      - **AGL Trinidad Holdings, LLC (DE)**
        - **Tropical Express Container Service Trinidad Unlimited (Trinidad and Tobago)**

Denotes operating utility

Denote retail subsidiaries

Denotes gas marketing and gas storage subsidiaries and related joint venture

(1) Joint venture with Duke Energy Florida, Inc. and Florida Power & Light Company
(2) Joint Venture with Piedmont Energy Company
(3) Holds a 1% GP interest in Sequent Energy Management, L.P.
(4) Holds a 99% LP interest in Sequent Energy Management, L.P.
(5) Joint venture between Nicor Oil and Gas Corporation and APC Associates
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(7) Doing business as Pivotal Home Solutions and other d/b/a names in various states
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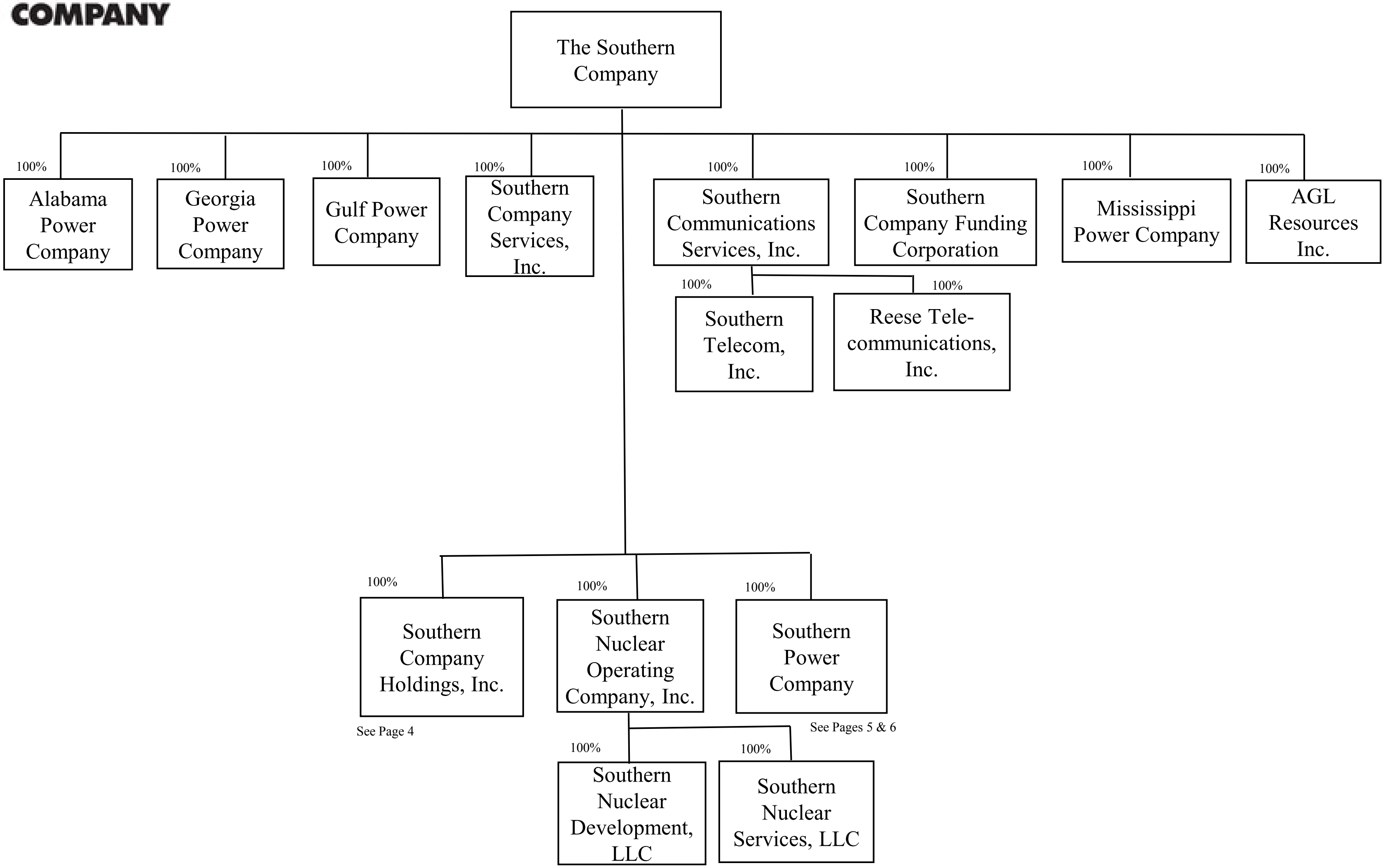
* Discontinued Operations



NOTE: This is a projected organizational chart, for demonstration only.

Exhibit 11

The Southern Company's California Solar Facilities
(listed by project LLC)

California Solar Facility	*Company*	*Southern Ownership Capacity (MWs)*	*Southern Ownership Percentage*
Campo Verde	*Campo Verde Solar, LLC*	*133*	*90%*
Adobe	*Adobe Solar, LLC*	*18*	*90%*
Solar Gen 2	*SG2 Imperial Valley, LLC*	*83*	*51%*
Lost Hills-Blackwell	*Lost Hills Solar, LLC and Blackwell Solar, LLC*	*17*	*51%*
North Star	*North Star Solar, LLC*	*31*	*51%*
Tranquillity	*RE Tranquillity, LLC and RE Tranquillity BAAH, LLC*	*102*	*51%*
Desert Stateline	*Desert Stateline, LLC*	*153*	*51%*
Morelos	*GASNA 31P, LLC*	*14*	*90%*