2013

PROXY STATEMENT AND NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

SOUTHERN COMPANY

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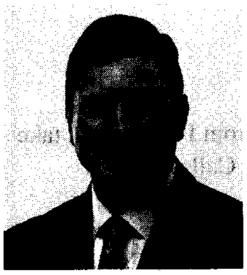
Letter to Stockholders

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



Dear Fellow Stockholder:

You are invited to attend the 2013 Annual Meeting of Stockholders at 10 a.m. ET on Wednesday, May 22, 2013, at The Lodge Conference Center at Callaway Gardens, Pine Mountain, Georgia.

Southern Company continues to make great strides in its efforts to provide clean, safe, reliable, affordable energy to our 4.4 million customers — building the nation's only fully diversified generation portfolio that includes new nuclear, 21st century coal, natural gas, renewables, and energy efficiency. We are harnessing the power of innovation to help make that goal a reality, while promoting the importance of long-term energy security throughout all of North America.

At the annual meeting, I will report on our accomplishments from 2012, as well as our plans for 2013 and beyond. We will also elect our Board of Directors and vote on the other matters set forth in the accompanying Notice.

Whether or not you plan to attend the meeting, your vote is important. Please review the proxy material and vote by internet, phone, or mail as soon as possible.

This Proxy Statement includes Appendix E, the 2012 Annual Report with 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 22nd. Thank you for your continued support of Southern Company.

Thomas A. Fanning

Thomas A. Fanning

Notice of Annual Meeting of Stockholders of The Southern Company

DATE: Wednesday, May 22, 2013

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 13 directors;
2. To ratify the appointment of Deloitte & Touche LLP as The Southern Company's independent registered public accounting firm for 2013;
3. To approve on a non-binding advisory basis The Southern Company's named executive officers' compensation;
4. To ratify a by-law amendment removing the mandatory retirement age provision for non-employee directors;
5. To consider and vote on an amendment to The Southern Company's Certificate of Incorporation to reduce the two-thirds supermajority vote requirements in Article Eleventh to a majority vote;
6. To consider and vote on an amendment to The Southern Company's Certificate of Incorporation to reduce the 75% supermajority vote requirements in Article Thirteenth to a two-thirds vote; and
7. 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 25, 2013 are entitled to attend and vote at the meeting.

Annual Report to Stockholders

Appendix E to this Proxy Statement is Southern Company's 2012 Annual Report.

By Order of the Board of Directors, G. Edison Holland, Jr., Corporate Secretary, April 12, 2013

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 will save The Southern Company the expense and extra work of additional solicitation.

VOTE BY INTERNET	VOTE BY PHONE
www.proxyvote.com	**1-800-690-6903**
24 hours a day/7 days a week	**Toll-free 24 hours a day/7 days a week**
Instructions:	**Instructions:**
Read this Proxy Statement	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.	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 over the internet or by phone.

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Proxy Statement

Frequently Asked Questions

Q: When will the Proxy Statement be mailed?

A: The Proxy Statement will be mailed on or about April 12, 2013.

Q: Who can vote?

A: All stockholders of record at the close of business on the record date of March 25, 2013 may vote. On that date, there were 870,915,018 shares of The Southern Company (Southern Company or the Company) common stock (Common Stock) outstanding and entitled to vote.

Q: How do I give voting instructions?

A: You may attend the meeting and give instructions in person or, as mentioned previously, give instructions by the 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 a voting instruction form provided by your broker, bank, or nominee 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 2013 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 the matters being considered in Item Nos. 1, 2, and 3 and thus will have no affect on the outcome of these items. However, abstentions will have the same effect as votes "against" the proposals being considered in Item Nos. 4, 5, and 6, and broker non-votes will have the same effect as votes "against" the proposals being considered in Item Nos. 5 and 6.

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 New York Stock Exchange (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 (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.cfm** to view the 2013 Proxy Statement.

Q: What should I bring if I plan to attend the Annual Meeting?

A: You will be asked to present photo identification, such as a driver's license. 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.

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 2012 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 2012 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 2012 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 (800) 554-7626 or by mail at The Southern Company, c/o Computershare, P.O. Box 358035, Pittsburgh, PA 15252-8035. 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 item described 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 No. 1 through 3. For Item No. 4, the affirmative vote of a majority of the shares present and entitled to vote at the 2013

Annual Meeting is required for approval. For Item No. 5, the affirmative vote of at least two-thirds of the issued and outstanding shares is required for approval. For Item No. 6, the affirmative vote of at least 75% of the issued and outstanding shares is required for approval.

Q: When are stockholder proposals due for the 2014 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 2014 Annual Meeting of Stockholders is December 13, 2013. Proposals must be submitted in writing to Melissa K. Caen, Assistant 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 26, 2014.

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 Alliance Advisors LLC to assist with the solicitation of proxies for a fee of $8,500, plus reimbursement of out-of-pocket expenses and any agreed upon charges associated with additional solicitation. 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.

Important Notice Regarding the Availability of Proxy Materials for the 2013 Annual Meeting of Stockholders to be held on May 22, 2013:

The Company's 2013 Proxy Statement, which includes the 2012 Annual Report as an appendix, is also available free of charge on the Company's website at http://investor.southerncompany.com/proxy.cfm.

The Company's 2012 Annual Report to the Securities and Exchange Commission (SEC) on Form 10-K will be provided without charge upon written request to Melissa K. Caen, Assistant Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

Corporate Governance

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 13 members.

At the 2013 Annual Meeting, stockholders will elect 13 Directors. The nominees for election as Directors consist of 12 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 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 Investors/Corporate Governance or directly at http://investor.southerncompany.com/governance.cfm, including:

- Code of Ethics
- By-Laws of the Company
- 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

The Corporate Governance documents also may be obtained by requesting a copy from Melissa K. Caen, Assistant 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 received, or the Director's immediate family member 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 of the last three fiscal years, exceeds the greater of $1,000,000 or two percent of that company's consolidated gross revenues.

Additionally, a Director will not be deemed to be independent if the Director or the Director's spouse serves as an executive officer of a charitable organization to which the Company made discretionary contributions exceeding the greater of $1,000,000 or two percent of the organization's total annual charitable receipts.

In determining independence, the Board reviews and considers 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 review specifically included all ordinary course transactions with entities with which the Directors are associated. In particular, the Board reviewed transactions between subsidiaries of the Company and Vulcan Materials Company or its affiliates and transactions between the Company or its subsidiaries and SunTrust Banks, Inc. or its affiliates, as described under Certain Relationships and Related Transactions in this Proxy Statement. Mr. Donald M. James is the Chairman and Chief Executive Officer of Vulcan Materials Company. Mr. E. Jenner Wood III is the Chairman, President, and Chief Executive Officer of the Georgia/North Florida Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc. The Board determined that the Company and its subsidiaries followed the Company procurement policies and procedures, that the amounts were well under the thresholds contained in the Director independence requirements, and that Messrs. James and Wood, as applicable, did not have a direct or indirect material interest in the transactions.

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.

As a result of its annual review of Director independence, the Board affirmatively determined that none of the following persons who are currently serving as Directors or who served during 2012 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., Donald M. James, Dale E. Klein, J. Neal Purcell, 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 Presiding Director. Communications may be sent to the Company's Board or to specified Directors, including the Presiding Director, by regular mail or electronic mail. Regular mail should be sent to the attention of Melissa K. Caen, Assistant 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 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.

DIRECTOR COMPENSATION

Only non-employee Directors of the Company are compensated for service on the Board of Directors. The pay components for non-employee Directors are:

Annual retainers:

- $100,000 cash retainer
- Additional $12,500 cash retainer if serving as a chair of a committee of the Board
- Additional $12,500 cash retainer if serving as the Presiding Director of the Board

Annual equity grant:

- $105,000 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.

DIRECTOR DEFERRED COMPENSATION PLAN

The annual equity grant is required to be deferred in shares of Common Stock under the Deferred Compensation Plan for Directors of The Southern Company (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.

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 upon leaving the Board;
- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in 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 2012, 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)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Juanita Powell Baranco	112,500	105,000	0	0	892	218,392
Jon A. Boscia	107,291	105,000	0	0	962	213,253
Henry A. Clark III	112,500	105,000	0	0	826	218,326
David J. Grain (4)	5,914	6,210	0	0	227	12,351
H. William Habermeyer, Jr.	112,500	105,000	0	0	724	218,224
Veronica M. Hagen	107,291	105,000	0	0	959	213,250
Warren A. Hood, Jr.	100,000	105,000	0	0	896	205,896
Donald M. James	105,209	105,000	0	0	896	211,105
Dale E. Klein	100,000	105,000	0	0	724	205,724
J. Neal Purcell (5)	46,875	43,750	0	0	639	91,264
William G. Smith, Jr.	112,500	105,000	0	0	724	218,224
Steven R. Specker	100,000	105,000	0	0	879	205,879
Larry D. Thompson (6)	100,000	105,000	0	0	797	205,797
E. Jenner Wood III (7)	63,263	61,250	0	0	1,435	125,948

(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 reimbursements for taxes on imputed income associated with gifts and activities provided to attendees at Company-sponsored events.
(4) Mr. Grain was elected to the Board effective December 10, 2012.
(5) Mr. Purcell retired from the Board effective May 23, 2012.
(6) Mr. Thompson resigned from the Board effective December 10, 2012.
(7) Mr. Wood was elected to the Board effective May 23, 2012.

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 four times the annual Director cash retainer fee.

BOARD LEADERSHIP STRUCTURE

The Board believes that the combined role of Chief Executive Officer and Chairman is most suitable for the Company because Mr. Fanning 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 an independent Presiding Director having the duties described below, is in the best interest of stockholders because it provides the appropriate balance between independent oversight of management and the development of strategy.

PRESIDING DIRECTOR

Mr. Smith was appointed to serve as the Presiding Director effective May 23, 2012 until May 28, 2014. The Presiding Director is selected bi-annually by and from 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 Presiding Director or two or more other independent Directors. As the Presiding Director, Mr. Smith is responsible for chairing executive sessions and acting as the principal liaison between the Chairman and the non-management Directors. However, each Director is afforded direct and complete access to the Chairman at any time as such Director deems necessary or appropriate. The Presiding Director meets regularly with the Chairman and also serves as the primary contact Director for stockholders and other interested parties. The Presiding Director is also involved in communicating any sensitive issues to the Directors and chairing Board meetings in the absence of the Chairman.

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 Presiding Director chairs each of these executive sessions.

COMMITTEES OF THE BOARD

Committee Charters

Charters for each of the five standing committees can be found at the Company's website — www.southerncompany.com under Investors/Corporate Governance.

Audit Committee:

- Current members are Mr. Boscia *(Chair),* Mr. Grain, and Mr. Hood
- Met 10 times in 2012
- Oversees the Company's financial reporting, audit processes, internal controls, and legal, regulatory, and ethical compliance; appoints the Company's independent registered public accounting firm, approves its services and fees, and establishes and reviews the scope and timing of its audits; reviews and discusses the Company's financial statements with management 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; and recommends the filing of the Company's annual financial statements with the SEC.

The Board has determined that the members of the Audit Committee are independent as defined by the 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.

Compensation and Management Succession Committee (Compensation Committee):

- Current members are Ms. Hagen *(Chair)*, Mr. Clark, Mr. Habermeyer, and Mr. Smith
- Met seven times in 2012
- Evaluates performance of executive officers and establishes their compensation, administers executive compensation plans, and reviews management succession plans. Annually reviews a tally sheet of all components of the executive officers' compensation and takes 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.

Governance

During 2012, 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 2012, 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:

- Current members are Mr. Clark (*Chair*), Mr. James, and Mr. Smith
- Met seven times in 2012
- Reviews the Company's financial matters, recommends actions such as dividend philosophy to the Board, and approves certain capital expenditures.
- Provides information to the Compensation Committee regarding the Company's financial plan and goals.

The Board has determined that each member of the Finance Committee is independent.

Governance Committee:

- Current members are Ms. Baranco (*Chair*), Mr. James, Dr. Klein, Dr. Specker, and Mr. Wood
- Met six times in 2012
- Oversees the composition of the Board and its committees, determines non-management Directors' compensation, maintains the Company's Corporate Governance Guidelines, coordinates the performance evaluations of the Board and its committees, and reviews stock ownership of 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.

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 setting forth the candidate's qualifications, relevant biographical information, and signed consent to serve. These materials should be submitted in writing to the Company's Assistant Corporate Secretary and received by that office by December 13, 2013 for consideration by the Governance Committee as a nominee for election at the Annual

Meeting of Stockholders to be held in 2014. 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, and public and private services, in the selection of candidates to serve on the Board. 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, 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, and number of other board memberships. 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. 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.

Mr. David J. Grain was identified by a third-party search firm and was recommended to members of the Governance Committee. Mr. Grain was recommended by the Governance Committee for election to the Board and was elected as a Director effective December 10, 2012.

Nuclear/Operations Committee:

- Current members are Mr. Habermeyer (*Chair*), Ms. Baranco, Ms. Hagen, Dr. Klein, Dr. Specker, and Mr. Wood
- Met five times in 2012
- Oversees significant information, activities, and events relative to significant operations of the Southern Company system including nuclear and other generation facilities, transmission and distribution, fuel, and information technology initiatives.
- Provides information to the Compensation Committee on the Southern Company system's operational goals.

The Board has determined that each member of the Nuclear/Operations Committee is independent.

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. In addition, ongoing oversight responsibility for each of the Company's most significant risks is designated to the applicable committees at least annually. Each committee provides oversight of the significant risks as described in its charter or otherwise assigned by the Board. The committees report to the Board on their oversight activities and elevate review of risk issues to the Board as appropriate. For each committee, the Chief Executive Officer of the Company has designated a member of 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. The Audit Committee receives regular updates from Internal Auditing, as needed, and quarterly updates as part of the disclosure controls process.

DIRECTOR ATTENDANCE

The Board of Directors met seven times in 2012. Average Director attendance at all applicable Board and committee meetings was 99%. No nominee attended less than 75% of applicable meetings.

All Director nominees are expected to attend the Annual Meeting of Stockholders. Except for Mr. Boscia, all the members of the Board of Directors serving on May 23, 2012, the date of the 2012 Annual Meeting of Stockholders, attended the meeting.

Stock Ownership Table

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 December 31, 2012. 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	42,663	42,063	0	0
Art P. Beattie	291,121	0	284,988	127
Jon A. Boscia	73,687	14,687	0	0
W. Paul Bowers	817,569	0	805,249	0
Henry A. Clark III	8,919	8,919	0	0
Thomas A. Fanning	1,129,160	0	1,116,222	0
David J. Grain	711	211	0	500
H. William Habermeyer, Jr.	16,581	16,581	0	0
Veronica M. Hagen	23,044	23,044	0	0
Warren A. Hood, Jr.	33,335	32,733	0	0
Donald M. James	79,561	79,561	0	0
Dale E. Klein	6,279	6,279	0	0
Stephen Kuczynski	155,529	0	151,253	4,276
Charles D. McCrary	492,305	0	485,898	0
William G. Smith, Jr.	47,571	41,630	0	662
Steven R. Specker	5,593	5,593	0	0
E. Jenner Wood III	12,083	10,984	0	0
Directors, Nominees, and Executive Officers as a Group (24 people)	4,728,004	282,285	4,306,741	60,565

(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. 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.

STOCK OWNERSHIP OF CERTAIN OTHER BENEFICIAL OWNERS

According to a Schedule 13G/A filed with the SEC on February 8, 2013, (the Ownership Report), 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	Percentage of Class Owned
Common Stock	Blackrock, Inc. 40 East 52nd Street New York, NY 10022	51,559,488	5.90

According to the Ownership Report, Blackrock, Inc. held all of its shares as a parent holding company, or control person in accordance with Rule 13(d)-1(b)(1)(ii)(G). According to the Ownership Report, Blackrock, Inc. has sole voting power and sole investment power over its shares.

Matters to be Voted Upon

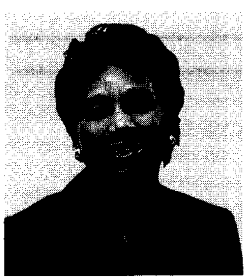
ITEM NO. 1 — ELECTION OF DIRECTORS

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 2014 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 possessing the collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and the Company's industry, as detailed below. The Governance Committee evaluated each nominee's independence from management, ability to provide sound and informed judgment, history of achievement reflecting superior standards, willingness to commit sufficient time, financial literacy, and 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, as well as the number of other board memberships each holds.

Juanita Powell Baranco



Age: 64

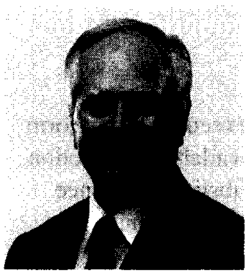
Director since: 2006

Board committees: Governance (Chair), Nuclear/Operations

Principal occupation: Executive Vice President and Chief Operating Officer of Baranco Automotive Group, automobile sales

Other directorships: None (formerly a Director of Cox Radio, Inc. and Georgia Power Company)

Director qualifications: 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 on the Board 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 John H. Harland Company Board of Directors. An active leader in the Atlanta community, Ms. Baranco has served as a Director of Cox Radio, Inc. She serves as Chair of the Board of Trustees for Clark Atlanta University and as a Director of the Catholic Foundation of North Georgia, the DeKalb Chamber of Commerce, and the Commerce Club. 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: 60

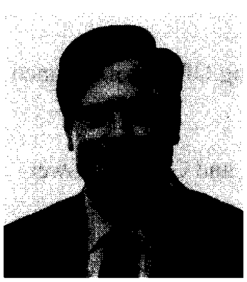
Director since: 2007

Board committee: Audit (Chair)

Principal occupation: Founder and President, Boardroom Advisors LLC, board governance consultancy firm, since March 2011

Other directorships: PHH Corporation (formerly a Director of Sun Life Financial Inc., Armstrong World Industries, Lincoln Financial Group, Georgia Pacific Corporation, and The Hershey Company)

Director qualifications: 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 The Hershey Company, where he chaired the Corporate Governance Committee and served on the Executive Committee, and 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. In addition, Mr. Boscia has served in leadership positions on other public company boards as well as not-for-profit and industry boards. His extensive background in finance, investment management, information technology, and corporate governance are valuable to the Board.



Henry A. "Hal" Clark III

Age: 63

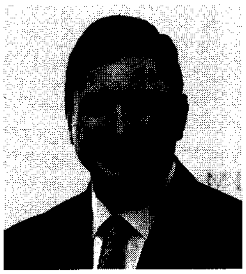
Director since: 2009

Board committees: Finance (Chair), Compensation and Management Succession

Principal occupation: Senior Advisor of Evercore Partners Inc. (formerly Lexicon Partners, LLC), corporate finance advisory firm, since July 2009

Other directorships: None

Director qualifications: 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.



Thomas A. Fanning

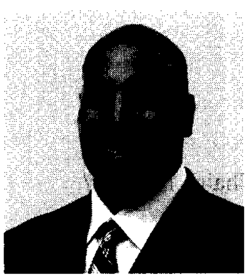
Age: 56

Director since: 2010

Principal occupation: Chairman of the Board, President, and Chief Executive Officer of the Company since December 2010

Other directorships: Federal Reserve Bank of Atlanta, Alabama Power Company, Georgia Power, and Southern Power Company

Director qualifications: Mr. Fanning had 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 Boards of a number of Southern Company's subsidiaries. He is also a Director of the Federal Reserve Bank of Atlanta, serving on the Executive Committee and the Audit Committee. Mr. Fanning served on the Board of The St. Joe Company from 2005 through September 2011. Mr. Fanning's knowledge of the day-to-day operations of an electric utility and the regulatory challenges of the industry uniquely qualify him to be a Director of the Company.



David J. Grain

Age: 50

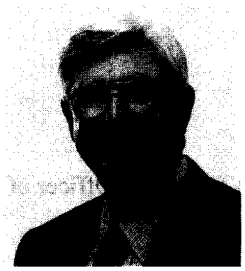
Director since: 2012

Board committee: Audit

Principal occupation: Founder and Managing Partner, Grain Management, LLC, private equity firm

Other directorships: Gateway Bank of Southwest Florida

Director qualifications: Mr. Grain is the Founder and Managing Partner of Grain Management, LLC, a private equity firm specializing in investments in wireless communications infrastructure throughout the United States, since 2006. He is also the Chief Executive Officer of Grain Communications Group, Inc. Grain Management, LLC's flagship funds manage capital on behalf of domestic institutional investors including academic endowments, public pension funds, and foundations. Before forming the Grain entities, Mr. Grain served as President of Global Signal, Inc., where he was hired to lead Pinnacle Holdings, Inc. (Pinnacle) from bankruptcy through its successful operational turnaround. After Pinnacle was renamed Global Signal, Inc. in 2004, Mr. Grain grew the company into one of the largest independent wireless communications tower companies in North America. In 2011, Mr. Grain was appointed by President Obama to the National Infrastructure Advisory Council. He also serves as chairman of the Florida State Board of Administration Investment Advisory Council as an appointee of former Governor Charlie Crist. Additionally, he is a Director of the Gateway Bank of Southwest Florida and Trustee of College of the Holy Cross. Mr. Grain's background in finance, investment management, wireless communications infrastructure, leadership, and civic involvement are valuable to the Board.



H. William Habermeyer, Jr.

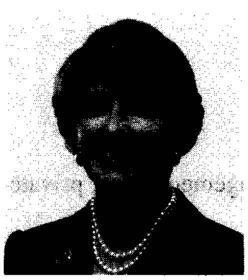
Age: 70

Director since: 2007

Board committees: Nuclear/Operations (Chair), Compensation and Management Succession

Other directorships: Raymond James Financial, Inc., USEC Inc.

Director qualifications: Mr. Habermeyer retired in 2006 from his position as President and Chief Executive Officer of Progress Energy Florida, Inc., a subsidiary of Progress Energy Inc., a diversified energy company. Mr. Habermeyer has a wealth of experience in utility business operations, with a focus on nuclear matters, which is valuable to the Board. He joined Progress Energy's predecessor Carolina Power & Light in 1993 and served in various leadership roles including Vice President of Nuclear Services and Environmental Support, Vice President of Nuclear Engineering, and Vice President of Progress Energy's Western Region. While overseeing the Western Region operations, Mr. Habermeyer was responsible for regional distribution management, customer support, and community relations. He serves on the Board of USEC Inc., a global energy company, where he is Chair of the Nomination and Governance Committee and a member of the Technology and Competition Committee. In addition, he is on the Audit Committee of Raymond James Financial Inc. Mr. Habermeyer is a retired Rear Admiral who served in the United States Navy for 28 years. His military medals include seven awards of the Legions of Merit, two Navy Commendation Medals, and service and campaign awards.



Veronica M. Hagen

Age: 67

Director since: 2008

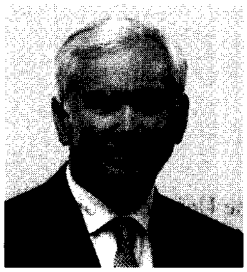
Board committees: Compensation and Management Succession (Chair), Nuclear/ Operations

Principal occupation: President and Chief Executive Officer of Polymer Group, Inc., engineered materials; Chief Executive Officer since April 2007; President since January 2011

Other directorships: Polymer Group, Inc., Newmont Mining Corporation

Director qualifications: Ms. Hagen's global operational management experience and commercial business leadership are valuable assets to the Board. Ms. Hagen has served as Director and Chief Executive Officer of Polymer Group, Inc. since April 2007 and as President since January 2011. 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 her resignation in 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 on the Environmental, Social Responsibility, Operations and Safety Committee and the Compensation Committee of the Board of Newmont Mining Corporation.

Warren A. Hood, Jr.



Age: 61

Director since: 2007

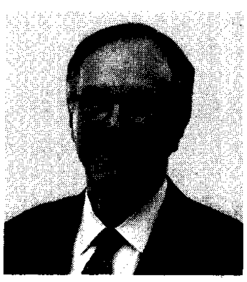
Board committee: Audit

Principal occupation: Chairman of the Board and Chief Executive Officer of Hood Companies, Inc., packaging and construction products

Other directorships: Hood Companies, Inc., BancorpSouth, Inc. (formerly a Director of Mississippi Power Company)

Director qualifications: 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. 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 on numerous corporate, community, and philanthropic boards, including Boy Scouts of America 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, financial experience, and civic involvement are valuable to the Board.

Donald M. James



Age: 64

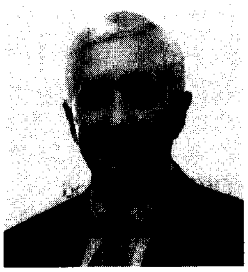
Director since: 1999

Board committees: Finance, Governance

Principal occupation: Chairman of the Board and Chief Executive Officer of Vulcan Materials Company, construction materials

Other directorships: Vulcan Materials Company, Wells Fargo & Company (formerly a Director of Protective Life Corporation)

Director qualifications: 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 of the Southern Division. 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 Director of the UAB Health System, Boy Scouts of Central Alabama, and the Economic Development Partnership of Alabama, Inc. In addition, he serves on the Finance and 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.



Dale E. Klein

Age: 65

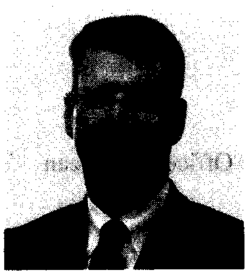
Director since: 2010

Board committees: Governance, Nuclear/Operations

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, university system

Other directorships: Pinnacle West Capital Corporation, Arizona Public Service Company

Director qualifications: Dr. Klein was Commissioner from 2009 to 2010 and Chairman from 2006 to 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 to 2006. Dr. Klein has more than 30 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. Mr. Klein's expertise in nuclear energy regulation and operations, technology, and safety is valuable to the Board.



William G. Smith, Jr.

Age: 59

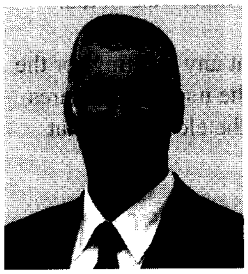
Director since: 2006, Presiding Director since May 23, 2012

Board committees: Compensation and Management Succession, Finance

Principal occupation: Chairman of the Board, President, and Chief Executive Officer of Capital City Bank Group, Inc., banking

Other directorships: Capital City Bank Group, Inc., Capital City Bank

Director qualifications: Mr. Smith began his career at Capital City Bank in 1978, where he worked in a number of capacities 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 has also 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: 67

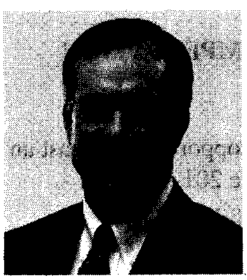
Director since: 2010

Board committees: Governance, Nuclear/Operations

Other directorships: Trilliant Incorporated

Director qualifications: 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 has 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.

E. Jenner Wood III



Age: 61

Director since: 2012

Board committees: Governance, Nuclear/Operations

Principal occupation: Chairman, President, and Chief Executive Officer of the Georgia/North Florida Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc., banking

Other directorships: Oxford Industries, Inc., Crawford & Company (formerly a Director of Georgia Power)

Director qualifications: Mr. Wood is currently the Chairman, President, and Chief Executive Officer of the Georgia/North Florida Division of SunTrust Bank where he is responsible for managing retail, commercial, and private wealth banking in the Greater Atlanta region and throughout the State of Georgia and North Florida. He was elected to his current position in April 2010. He also has served as an Executive Vice President of SunTrust Banks, Inc. since July 2005. From 2002 to 2010, he served as Chairman, President, and Chief Executive Officer of SunTrust Bank Central Group with responsibility over Georgia and Tennessee. Mr. Wood has more than 37 years of experience in the banking industry and has served in numerous management positions in corporate and trust and investment management with SunTrust Banks, Inc. He served as a member of the Board of Georgia Power, the largest subsidiary of the Company 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. He serves also as a Director of Crawford & Company, where he is a member of the Compensation Committee and 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, and the Jesse Parker Williams 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 — RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit Committee of the Board of Directors has appointed Deloitte & Touche LLP (Deloitte & Touche) as the Company's independent registered public accounting firm for 2013. This appointment is being submitted to stockholders for ratification. Representatives of Deloitte & Touche will be present at the 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. 2.

ITEM NO. 3 — ADVISORY VOTE ON NAMED EXECUTIVE OFFICERS' COMPENSATION (the Say-on-Pay vote)

At the 2012 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 2012 Proxy Statement for the 2012 Annual Meeting of Stockholders. At the meeting, stockholders strongly approved the proposal, with more than 95% 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 & Analysis (CD&A), 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 was strong in 2012 and 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 2013 Annual Meeting of Stockholders pursuant to the compensation disclosure rules of the Securities and Exchange Commission, including the Compensation Discussion and Analysis, the 2012 Summary Compensation Table, and the other related tables and accompanying narrative set forth in this Proxy Statement."

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 3.

ITEM NO. 4 — RATIFICATION OF AMENDMENT TO THE COMPANY'S BY-LAWS REMOVING THE MANDATORY RETIREMENT AGE PROVISION FOR NON-EMPLOYEE DIRECTORS

The Company's Board of Directors amended Section 15 of the Company's By-Laws, as amended (By-Laws), to remove the mandatory retirement age provision for non-employee directors effective as of February 11, 2013. This amendment is being submitted to stockholders for ratification as required by the By-Laws.

Background of This Item

Prior to this amendment, non-employee directors could not stand for election or re-election past their 70th birthday. This restriction was included in both the By-Laws and the Company's Corporate Governance Guidelines (Guidelines). Based on market trends of companies in the S&P 500, the Board determined that the Company's mandatory retirement age for non-employee directors should be increased. The Board also determined that the mandatory retirement age provision should only be set forth in the Guidelines in order to allow the Board to continue to monitor and more easily react to market trends and make timely changes to keep the Company current with best practices. Concurrently with its approval of the amendment to the By-Laws to remove the mandatory retirement age provision from the By-Laws, the Board approved an amendment to the Guidelines so that non-employee directors do not stand for re-election after reaching age 72.

Amendment

The amendment to Section 15 of the By-Laws includes the following:

- Removal of the provision relating to the eligibility of a non-employee director to stand for election or re-election after reaching his or her 70th birthday.
- Removal of the provision that references the eligibility of a non-employee director to stand for election or re-election in connection with service on the Independent Litigation Committee, which was dissolved effective March 9, 1992.

The text of the amendment, marked to show changes to prior Section 15 of the By-Laws, is included as Appendix A to this Proxy Statement.

The affirmative vote of a majority of the shares present and entitled to vote at the annual meeting is required for ratification of the amendment of the By-Laws as presented in this Item No. 4. In the event the amendment to the By-Laws is not ratified by stockholders, the amendment will cease to be effective following the 2013 Annual Meeting.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 4.

ITEM NO. 5 — AMENDMENT TO THE COMPANY'S CERTIFICATE OF INCORPORATION TO REDUCE THE TWO-THIRDS SUPERMAJORITY VOTE REQUIREMENTS IN ARTICLE ELEVENTH TO A MAJORITY VOTE

The Board of Directors has determined that it would be in the best interest of the Company and its stockholders to reduce the current two-thirds supermajority vote requirements in Article Eleventh of the Company's Certificate of Incorporation, as amended (Certificate of Incorporation), to a majority vote.

Background of This Item

Article Eleventh of the Certificate of Incorporation currently requires the affirmative vote of the holders of at least two-thirds of the Company's issued and outstanding Common Stock in order to:

- authorize or create any class of stock preferred as to dividends or assets over the Common Stock or reclassify the Common Stock or change the issued shares of Common Stock into the same or a greater or less number of shares of Common Stock either with or without par value or reduce the par value of the Common Stock (collectively, Stock Changes); and
- amend, alter, change, or repeal subdivision (2) of Article Ninth (with respect to working capital determinations), Article Twelfth (with respect to preemptive rights), Article Eleventh (with respect to Stock Changes and amendments to the Certificate of Incorporation), or in any amendment to the Certificate of Incorporation which provides for the vote of the holders of at least two-thirds of the issued and outstanding Common Stock.

Supermajority vote requirements like the ones contained in Article Eleventh of the Certificate of Incorporation are intended to facilitate corporate governance stability and provide protection against self-interested action by large stockholders by requiring broad stockholder consensus to make certain fundamental changes. While the Board recognizes these protections are important and in the best interests of stockholders, the Board also notes that many stockholders and commentators now view these provisions as limiting a board's accountability to stockholders and the ability of stockholders to effectively participate in corporate governance.

The Board is committed to implementing and maintaining effective corporate governance policies and practices which ensure that the Company is governed with high standards of ethics, integrity, and accountability and in the best interest of the Company's stockholders. After considering stockholder input, including a stockholder proposal, and the arguments in favor of and against the existing supermajority vote requirements in Article Eleventh, the Board has determined that reducing each of the two-thirds supermajority vote requirements in Article Eleventh to a majority vote requirement would preserve legitimate stockholder protections while enhancing the Board's accountability to the Company's stockholders and increasing the ability of stockholders to participate effectively in the Company's corporate governance.

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 Article Eleventh to reduce the two-thirds supermajority vote requirement to a majority vote requirement to (1) effect any Stock Changes and (2) amend, alter, change, or repeal certain provisions of the Certificate of Incorporation.

Amendment

The amendment to Article Eleventh of the Certificate of Incorporation includes the following:

- Replace the two-thirds supermajority vote requirement with a requirement that the affirmative vote of a majority of the issued and outstanding shares of the Company's Common Stock is required to approve any Stock Change; and
- Remove the two-thirds supermajority vote requirement necessary to amend, alter, change, or repeal certain provisions of the Certificate of Incorporation as more fully described above so that all amendments, alteration, changes, or repeals of the Certificate of Incorporation require the affirmative vote of a majority of the issued and outstanding shares of the capital stock of the Company, which is the default voting standard for such actions under Delaware law.

The text of the proposed amendment to Article Eleventh of the Certificate of Incorporation, marked to show changes from the current Article Eleventh, is included as Appendix B to this Proxy Statement.

The affirmative vote of at least two-thirds of the issued and outstanding shares of the Common Stock is required for approval of the amendment to Article Eleventh of the Certificate of Incorporation as presented in this Item No. 5.

If the proposed amendment is approved by the Company's stockholders, it will become effective upon filing of a Certificate of Amendment to the Certificate of Incorporation with the Secretary of State of the State of Delaware, which filing the Company would make promptly after the Annual Meeting.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 5.

ITEM NO. 6 — AMENDMENT TO THE COMPANY'S CERTIFICATE OF INCORPORATION TO REDUCE THE 75% SUPERMAJORITY VOTE REQUIREMENTS IN ARTICLE THIRTEENTH TO A TWO-THIRDS VOTE

The Board of Directors has determined that it would be in the best interest of the Company and its stockholders to reduce the current 75% supermajority vote requirements in Article Thirteenth of the Certificate of Incorporation to a two-thirds vote.

Background of This Item

Article Thirteenth, known as the "fair price" provision, requires that certain minimum price and procedural requirements, intended for the protection of the Company and its stockholders as a whole, be observed by any person or group (Interested Stockholder) which acquires more than five percent of the issued and outstanding shares of capital stock of the Company having voting power (Voting Stock) and then seeks to accomplish a merger or other business combination or transaction which would eliminate or could significantly change the interests of the remaining stockholders (Business Combination), unless approved by a majority of disinterested Directors.

Article Thirteenth provides that the affirmative vote of the holders of at least (1) 75% of the issued and outstanding Voting Stock, voting together as a single class, and (2) a majority of the issued and outstanding Voting Stock beneficially owned by persons other than the Interested Stockholder, voting together as a single class, is required in order to:

- approve a Business Combination with an Interested Stockholder if the minimum price and procedural requirements specified in Article Thirteenth are not followed; and
- amend, alter, change, repeal, or adopt any provision inconsistent with Article Thirteenth of the Certificate of Incorporation.

As is the case in the supermajority vote requirements in Article Eleventh of the Certificate of Incorporation described above in Item No. 5, the supermajority vote requirements contained in Article Thirteenth of the Certificate of Incorporation are intended to facilitate corporate governance stability and provide protection against self-interested action by large stockholders by requiring broad stockholder consensus to make certain fundamental changes. Specifically, the supermajority vote requirements contained in Article Thirteenth, which were added to the Certificate of Incorporation following stockholder approval in 1987, are designed to deter an acquiring party from using two-tier pricing and similar inequitable tactics in an attempt to take over the Company and help assure fair treatment of all stockholders in the event of a takeover attempt. While the Board believes that the protection that the supermajority vote requirements in Article Thirteenth provide is important and is in the best interest of the Company and its stockholders, the Board also notes that many stockholders and commentators now view these provisions as limiting a board's accountability to stockholders and the ability of stockholders to effectively participate in corporate governance. In addition, others have argued that supermajority vote requirements for "fair price" provisions have the effect of discouraging legitimate offers for a company by making them more expensive.

The Board is committed to implementing and maintaining effective corporate governance policies and practices which ensure that the Company is governed with high standards of ethics, integrity, and accountability and in the best interest of the Company's stockholders. After considering stockholder input, including a stockholder proposal, and the arguments in favor of and against the existing supermajority vote requirements in Article Thirteenth, the Board has determined that lowering the voting requirements from 75% to 66-2/3% is more reflective of current practice and will enhance accountability to stockholders while preserving the legitimate protections afforded by the supermajority vote requirements in Article Thirteenth.

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 Sections 1 and 6 of Article Thirteenth to reduce the 75% supermajority vote requirement to a 66-2/3% threshold to (a) approve certain Business Combinations with Interested Stockholders or (b) amend, alter, change, repeal, or adopt any provisions inconsistent with Article Thirteenth.

Amendment

The amendment to Sections 1 and 6 of Article Thirteenth of the Certificate of Incorporation will reduce the 75% supermajority vote requirement to a 66 2-3% vote requirement in order to:

- approve a Business Combination with an Interested Stockholder if the minimum price and procedural requirements specified in Article Thirteenth are not followed; and
- amend, alter, change, repeal, or adopt any provision inconsistent with Article Thirteenth of the Certificate of Incorporation.

The text of the proposed amendment to Sections 1 and 6 of Article Thirteenth of the Certificate of Incorporation, marked to show changes from the current Sections 1 and 6 of Article Thirteenth, is included as Appendix C to this Proxy Statement.

The affirmative vote of at least 75% of the issued and outstanding shares of the Common Stock is required for approval of the amendment to Article Thirteenth of the Certificate of Incorporation as presented in this Item No. 6.

If the proposed amendment is approved by the Company's stockholders, it will become effective upon filing of a Certificate of Amendment to the Certificate of Incorporation with the Secretary of State of the State of Delaware, which filing the Company would make promptly after the Annual Meeting.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 6.

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 2012 Annual Report to Stockholders attached hereto as Appendix E 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" 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 Statement on Auditing Standards No. 61, as amended (American Institute of Certified Public Accountants, Professional Standards, Vol. 1, AU Section 380), as adopted by the Public Company Accounting Oversight Board (PCAOB) in Rule 3200T. 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 10 meetings during 2012.

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, 2012 and filed with the SEC. The Audit Committee also reappointed Deloitte & Touche as the Company's independent registered public accounting firm for 2013. Stockholders will be asked to ratify that selection at the Annual Meeting of Stockholders.

Members of the Audit Committee:

Jon A. Boscia, Chair
David J. Grain
Warren A. Hood, Jr.

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 2012 and 2011.

	2012	2011
	(in thousands)	
Audit Fees (1)	$11,695	$10,970
Audit-Related Fees (2)	500	871
Tax Fees	0	0
All Other Fees (3)	31	24
Total	$12,226	$11,865

(1) Includes services performed in connection with financing transactions.

(2) Includes non-statutory audit services in both 2012 and 2011.

(3) Represents registration fees for attendance at Deloitte & Touche-sponsored education seminars and subscription fees for Deloitte & Touche's technical accounting research tool.

The Audit Committee has adopted a Policy on Engagement of the Independent Auditor for Audit and Non-Audit Services (see Appendix D) 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.

Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

This section describes the compensation program for the Company's Chief Executive Officer and Chief Financial Officer in 2012, as well as each of the Company's other three most highly compensated executive officers serving at the end of the year. Collectively, these officers are referred to as the named executive officers.

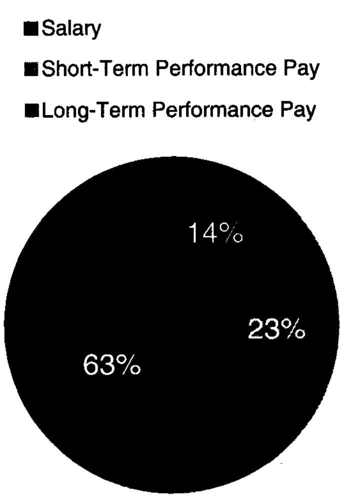
Thomas A. Fanning	Chairman of the Board, President, and Chief Executive Officer
Art P. Beattie	Executive Vice President and Chief Financial Officer
W. Paul Bowers	Executive Vice President of the Company and President and Chief Executive Officer of Georgia Power
Stephen E. Kuczynski	President and Chief Executive Officer of Southern Nuclear Operating Company, Inc. (Southern Nuclear)
Charles D. McCrary	Executive Vice President of the Company and President and Chief Executive Officer of Alabama Power Company (Alabama Power)

Executive Summary

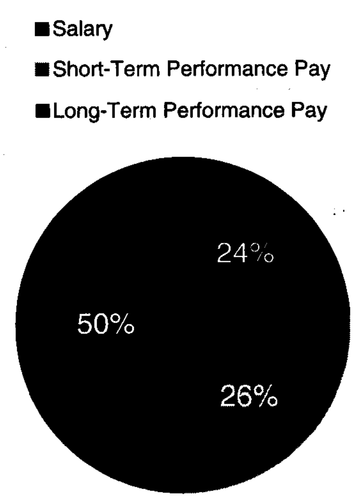
Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2012.

Chief Executive Officer (1)



Other Named Executive Officers (1)



(1) Salary is the actual amount paid in 2012, Short-Term Performance Pay is the actual amount earned in 2012 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2012. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A.

Business unit financial and operational and Company earnings per share (EPS) goal results for 2012 are shown below:

Financial: 129% of Target   Operational: 169% of Target   EPS: 128% of Target

The Company's total shareholder return has been:

1-Year: -3.4%   3-Year: 13.9%   5-Year: 7.1%

These levels of achievement resulted in payouts that were aligned with performance.

Compensation and Benefit Beliefs

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 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 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 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 2012 Annual Meeting of Stockholders. In light of the significant support of the stockholders (95% 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 and is aligned with the Company's financial and operational performance and is 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:

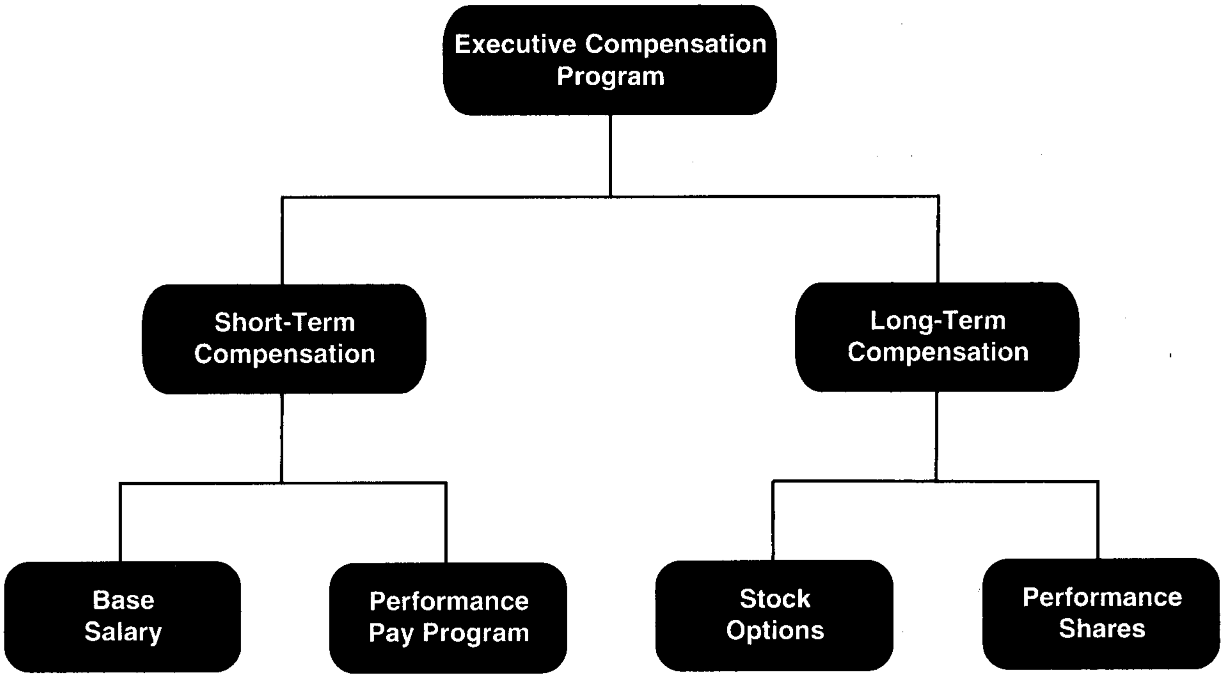
- Business unit performance, which includes return on equity (ROE) or net income, and operational performance, compared to target performance levels established early in the year, and EPS determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay 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 26,000 employees of the Southern Company system. Stock options and performance shares are granted to approximately 3,500 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 2012 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

For the named executive officers, the Compensation Committee reviews compensation data from large, publicly-owned electric and gas utilities. The data was developed and analyzed by Pay Governance. The companies included each year in the primary peer group are those whose data is available through the consultant's database. Those companies are drawn from this list of primarily regulated utilities of $6 billion in revenues and up.

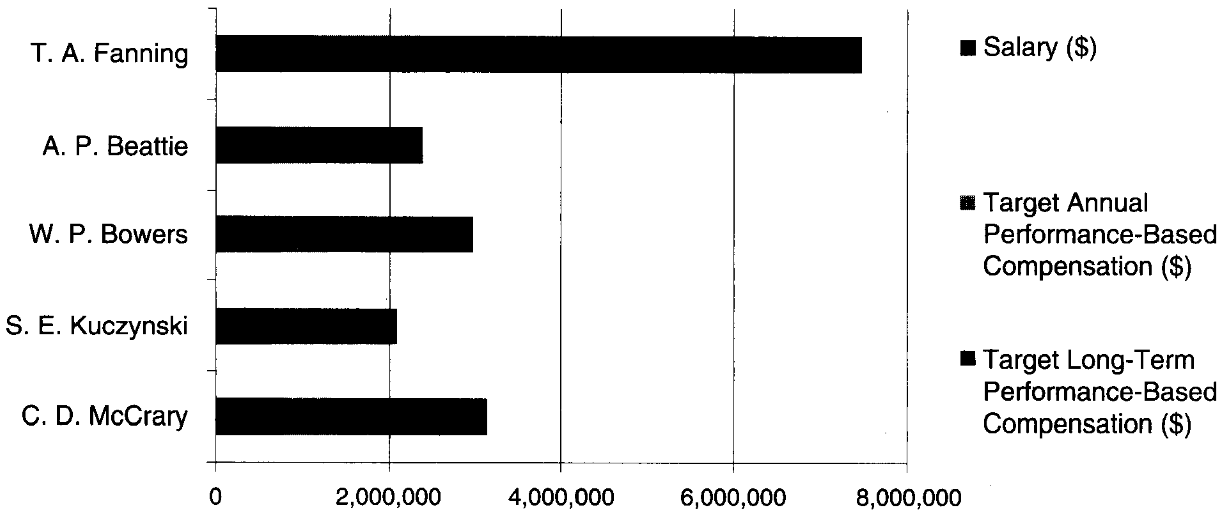
Ameren Corporation	**Exelon Corporation**
American Electric Power Company, Inc.	FirstEnergy Corp.
Bg US Services, Inc.	**Kinder Morgan Energy Partners, L.P.**
Calpine Corporation	MidAmerican Energy Company
CenterPoint Energy, Inc.	**NextEra Energy, Inc.**
CMS Energy Corporation	NRG Energy, Inc
Consolidated Edison, Inc.	**Pepco Holdings, Inc**
Constellation Energy Group, Inc.	PG&E Corporation
DCP Midstream LLC	**PPL Corporation**
Dominion Resources, Inc.	Progress Energy, Inc.
DTE Energy Company	**Public Service Enterprise Group Inc.**
Duke Energy Corporation	Sempra Energy
Edison International	**Tennessee Valley Authority**
Enbridge Energy Partners, LP	The Williams Companies, Inc.
Energy Future Holdings Corp.	**Xcel Energy Inc.**
Entergy Corporation	

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. 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 2012 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 2012 for each named executive officer. As the chart below depicts, the fixed pay (base salary) for Mr. Fanning is 15% of his total target compensation opportunity and ranges from 25% to 31% for the other named executive officers. Variable (at risk) performance-based compensation is 85% for Mr. Fanning and 69% to 75% for the other named executive officers.



The salary levels shown above were not effective until March 2012. 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 2012.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $3.39 per option and performance shares at $41.99 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 were 40% and 60%, respectively, of the long-term value shown above.

In 2011, Pay Governance analyzed the level of actual payouts for 2010 performance under the annual Performance Pay Program 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 2012. That analysis was updated in 2012 by Pay Governance for 2011 performance, and those findings were used in establishing goals for 2013.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2012 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2012. Base salary increases for each of the named executive officers were recommended in 2012 for the Compensation

Committee's approval by Mr. Fanning, except for his own salary. Those recommendations took into account the market data provided by the Compensation Committee's independent compensation consultant, 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 results of operations in prior years. The Compensation Committee approved the recommended salaries in 2012.

Base salaries were increased 3% for Messrs. Bowers, Kuczynski, and McCrary. Base salaries for Messrs. Beattie and Fanning were significantly below market and were increased 13% and 5%, respectively.

2012 Performance-Based Compensation

This section describes performance-based compensation for 2012.

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 2012, the Company strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices; and
- Meeting energy demand with the best economic and environmental choices.

In 2012, the Company also focused on and rewarded:

- EPS growth;
- ROE – target performance level in the top quartile of comparable electric utilities;
- Dividend growth;
- Long-term, risk-adjusted total shareholder return; and
- Financial integrity — an attractive risk-adjusted return, sound financial policy, and a stable "A" credit rating.

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).

2012 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights

- Rewards achievement of annual goals:
    - EPS
    - Business unit financial performance (ROE or 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

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.

- For the traditional operating companies (Alabama Power, Georgia Power, Gulf Power Company (Gulf Power), and Mississippi Power), operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, and culture. For the nuclear operating company, Southern Nuclear, operational goals are safety, plant operations, 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.
- EPS is defined as the Company's earnings from continuing operations divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.
- For the traditional operating companies, the business unit financial performance goal is ROE, which is defined as the traditional operating company's net income divided by average equity for the year. For Southern Power Company (Southern Power), the business unit financial performance goal is net income, excluding net income from acquisitions.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial performance goals, such adjustments could include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the EPS goal was established and of sufficient magnitude to warrant recognition. The EPS goal results were decreased two cents per share to exclude the impact of an insurance recovery related to the MC Asset Recovery, LLC (MCAR) litigation settlement. This reduction decreased average payouts approximately seven percent. The Compensation Committee believed this adjustment was necessary because EPS goal results were increased in 2009 by the amount of the MCAR litigation settlement.

Under the terms of the program, no payout can be made if the Company's current earnings are not sufficient to fund the Common Stock dividend at the same level or higher than the prior year.

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, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affect 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.

Operational Goals *(continued)*	Description	Why It Is Important
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 is measured as a percentage of time the nuclear plant is operating, and accommodates generation reductions associated with planned outages. In addition, a subjective assessment of progress on the construction and licensing of Georgia Power's two new nuclear units, Plant Vogtle Units 3 and 4, is also in place.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
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.

Financial Performance Goals	Description	Why It Is Important
EPS	The Company's earnings from continuing operations divided by average shares outstanding during the year.	Supports commitment to provide stockholders solid risk-adjusted returns.
Business Unit ROE/Net Income	For the traditional operating companies, the business unit financial performance goal is ROE, which is defined as the traditional operating company's net income divided by average equity for the year. For Southern Power, the business unit financial performance goal is net income, excluding net income from acquisitions.	Supports delivery of stockholder value and contributes to the Company's sound financial policies and stable credit ratings.

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	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed targets	Industry best	Significantly exceed targets	Greater than top 10th percentile and Company best	Significant improvement
Target	Top quartile overall	Meet targets	Top quartile	Meet targets	Top 40th percentile	Improvement
Threshold	2nd quartile overall	Significantly below targets	2nd quartile	Significantly below targets	Top 60th percentile	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.

EPS and Business Unit Financial Performance:

The range of EPS, ROE, and Southern Power net income goals for 2012 is shown below. ROE goals vary from the allowed retail ROE range due to state regulatory accounting requirements, wholesale activities, other non-jurisdictional revenues and expenses, and other activities not subject to state regulation.

Level of Performance	EPS ($)	ROE (%)	Southern Power Net Income ($) (millions) (1)
Maximum	2.77	14.0	195
Target	2.64	12.0	155
Threshold	2.51	10.0	115

(1) Excluding net income from acquisitions.

For 2012, the Compensation Committee established a minimum EPS performance threshold that must be achieved. If EPS was less than $2.38 (90% of Target), not only would there have been no payout associated with EPS performance, but overall payouts under the Performance Pay Program would have been reduced by 10% of target.

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 of the Company's Board of Directors, respectively. For more information on these committees' responsibilities, see the committee descriptions in this Proxy Statement.

2012 Achievement

Actual payouts were determined by adding the payouts derived from EPS and applicable business unit operational and financial performance goal achievement for 2012 and dividing by three. EPS exceeded the minimum threshold established and therefore payouts were not affected. Actual 2012 goal achievement is shown in the following tables.

Operational Goal Results:

Corporate

Aggregate Operating Company Goal	Achievement Percentage
Customer Satisfaction	167
Reliability	174
Availability	170
Safety	200
Culture	138

Alabama Power

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	174
Availability	200
Safety	164
Culture	123

Georgia Power

Goal	Achievement Percentage
Customer Satisfaction	167
Reliability	171
Availability	77
Safety	163
Culture	141

Southern Nuclear

Southern Nuclear Goal	Achievement Percentage
Nuclear Safety	162
Nuclear Reliability	200
Vogtle Units 3 and 4 Assessment	150
Culture	139

Overall, the levels of achievement shown above resulted in an operational goal performance factor for Corporate, Alabama Power, Georgia Power, and Southern Nuclear of 169%, 175%, 143%, and 171%, respectively.

Financial Performance Goal Results:

Goal	Result	Achievement Percentage
EPS (excluding MCAR insurance recovery)	$2.67	128
Alabama Power ROE	13.10%	155
Georgia Power ROE	12.76%	138
Average Alabama Power and Georgia Power ROE	12.93%	147
Aggregate ROE	12.55%	129
Southern Power net income (excluding $4.5 million from acquisitions)	$171 million	140

Calculating Payouts:

Each named executive officer had a target Performance Pay Program opportunity, based on his position, set by the Compensation Committee at the beginning of 2012. Targets are set as a percentage of base salary. Mr. Fanning's target was set at 115%. For Messrs. Beattie, Bowers, and McCrary, the targets were set at 75% each and, for Mr. Kuczynski, it was set at 65%. 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 Messrs. Bowers and McCrary, payout is based on achievement of the ROE and operational goals of Georgia Power and Alabama Power, respectively. For Mr. Kuczynski, payout is based on the average ROE for Alabama Power and Georgia Power and the nuclear operations goals. For Messrs. Fanning and Beattie, payout is based on the aggregate ROE goal performance results for the traditional operating companies (90%) and Southern Power net income (10%) and the traditional operating companies' operational goal results (90%) and nuclear operations goal results (10%).

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 pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
T. A. Fanning	1,293,750	142	1,837,125
A. P. Beattie	471,549	142	669,600
W. P. Bowers	557,689	136	758,457
S. E. Kuczynski	418,438	148	619,288
C. D. McCrary	586,027	152	890,761

Long-Term Performance-Based Compensation

2012 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

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. The long-term awards provide an incentive to grow stockholder value.

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 2012, except restricted stock units.

	Value of Options ($)	Value of Performance Shares($)	Total Long-Term Value ($) (1)
T. A. Fanning	2,025,000	3,037,473	5,062,473
A. P. Beattie	515,558	773,300	1,288,858
W. P. Bowers	669,227	1,003,813	1,673,040
S. E. Kuczynski	411,997	617,967	1,029,964
C. D. McCrary	703,232	1,054,831	1,758,063

(1) Mr. Fanning's long-term value was adjusted upward by the Compensation Committee from 425% of base salary to 450% of base salary in recognition of his outstanding performance in 2011.

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 2012, 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 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 in the 2012 Annual Report attached as Appendix E to this Proxy Statement (Financial Statements). For 2012, the Black-Scholes value on the grant date was $3.39 per stock option.

Performance Shares

2012-2014 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 2012, the value per unit was $41.99. 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, 2012 through December 31, 2014), 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 the Philadelphia Utility Index and the 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. The Philadelphia Utility Index was chosen because it is a published index and, because it includes a larger number of peer companies, it can mitigate volatility in results over time, providing an appropriate level of balance. The peer groups vary from the Market Data peer group due to the timing and criteria of the peer selection process; however, there is significant overlap. The results of the two peer groups will be averaged. 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 Philadelphia Utility Index on the grant date are listed below.

Ameren Corporation	Entergy Corporation
American Electric Power Company, Inc.	Exelon Corporation
CenterPoint Energy, Inc.	FirstEnergy Corp.
Consolidated Edison, Inc.	NextEra Energy, Inc.
Covanta Holding Corporation	Northeast Utilities
Dominion Resources, Inc.	PG&E Corporation
DTE Energy Company	Public Service Enterprise Group Inc.
Duke Energy Corporation	The AES Corporation
Edison International	Xcel Energy Inc.
El Paso Electric Company	

The companies in the custom peer group on the grant date are listed below.

Alliant Energy Corporation	NSTAR
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	Progress Energy, Inc.
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Wisconsin Energy Corporation
Edison International	Xcel Energy Inc.
Northeast Utilities	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2012 through 2014 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Groups	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.

2010-2012 Payouts

The first performance share grants were made in 2010 with a three-year performance period that ended on December 31, 2012. Based on the Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (152.5%) and the custom peer group (117.5%), the payout percentage was 135% of target. The following table shows the target and actual awards of performance shares for the named executive officers.

	Target Performance Shares (#)	Performance Shares Earned (#)
T. A. Fanning	25,956	35,041
A. P. Beattie	4,150	5,603
W. P. Bowers	25,920	34,992
S. E. Kuczynski (1)	0	0
C. D. McCrary	25,861	34,912

(1) Mr. Kuczynski was not an employee of the Southern Company system until 2011.

Performance Dividends

The Compensation Committee terminated the Performance Dividend Program in 2010. The value of performance dividends represented a significant portion of long-term performance-based compensation that was awarded prior to 2010. At target performance levels, performance dividends represented up to 65% of the total long-term value granted over the 10-year term of stock options. Therefore, because performance dividends were awarded for years prior to 2010, in fairness to participants, the outstanding performance dividend awards were not cancelled. The Compensation Committee approved a three-year transition period, beginning with the 2007 through 2010 performance-measurement period, to continue to pay performance dividends, if earned, on stock options that were granted prior to 2010. The grant of performance shares, described above, replaced performance dividend awards beginning in 2010. Therefore, the final payout of performance dividends was made on stock options granted prior to 2010 that were outstanding at the end of the four-year performance-measurement period that ended on December 31, 2012, as reported in the Summary Compensation Table. Because performance shares are earned at the end of a three-year performance period, both the last award of performance dividends and the first award of performance shares were earned at the end of 2012.

Performance dividends ranged from 0% to 100% of the Common Stock dividend paid during the year per eligible stock option held at the end of the performance-measurement period. Actual payout depended on the Company's total shareholder return over a four-year performance-measurement period compared to a group of other electric and gas utility companies, as selected at the beginning of the performance-measurement period. The Compensation Committee selected a custom peer group and the Philadelphia Utility Index for the 2009 through 2012 grant. Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each custom peer group company's common stock and in the Philadelphia Utility Index at the beginning of each of 16 quarters. In the final year of the performance-measurement period, the Company's ranking in the peer groups was determined at the end of each quarter and the percentile ranking was multiplied by the actual Common Stock dividend paid in that quarter. To determine the total payout per stock option held at the end of the performance-measurement period, the four quarterly amounts earned were added together.

No performance dividends are paid if the Company's earnings are not sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

2012 Payout

The peer groups used to determine the 2012 payout for the 2009 through 2012 performance-measurement period consisted of the Philadelphia Utility Index and a custom peer group. See the discussion of performance shares in this CD&A for more information about the peer groups.

The scale below determined the percentage of each quarter's dividend paid in the last year of the performance-measurement period to be paid on each eligible stock option held at December 31, 2012, based on performance during the 2009 through 2012 performance-measurement period. Payout for performance between points was interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Quarterly Dividend Paid)
90th percentile or higher	100
50th percentile (Target)	50
10th percentile or lower	0

The Company's relative total shareholder return performance, as measured at the end of each quarter of the final year of the four-year performance-measurement period, resulted in a total payout of 70% of the target level (35% of the full year's Common Stock dividend), or $0.68. This amount was multiplied by each named executive officer's eligible outstanding stock options as of December 31, 2012 to calculate the payout under the program. The amount paid is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table.

Restricted Stock Units

In limited situations, restricted stock units are granted to address specific needs, including retention. If the recipient voluntarily terminates or is involuntarily terminated for cause, restricted stock units are forfeited. If the recipient remains employed with the Southern Company system or is involuntarily terminated not for cause, the restricted stock units will vest and be paid in Common Stock. 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. The Compensation Committee granted Mr. McCrary 43,908 restricted stock units that will vest on December 31, 2014 if he remains employed with the Southern Company system through the vesting date. On the grant date, the units were valued at $2,000,009. The Compensation Committee believes that given Mr. McCrary's expertise and age there is a retention risk and therefore providing a retention award was in the best interest of the Company. The Compensation Committee also sought advice from Pay Governance in determining market practice and the appropriate value of the award. See the Summary Compensation Table and Grants of Plan-Based Awards table and accompanying information for more information on this award of restricted stock units. Restricted stock units were granted to Messrs. Bowers and Kuczynski in 2010 and 2011, respectively, which are described in the Outstanding Equity Awards table and accompanying information.

Timing of Performance-Based Compensation

As discussed above, the 2012 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 stock options 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 2012 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.

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 opportunity. No excise tax gross-up would be provided. More information about severance arrangements is included in the section entitled Potential Payments upon Termination or Change-in-Control.

Perquisites

The Company provides limited perquisites to its executive officers, including the named executive officers. The perquisites provided in 2012, 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.

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. McCrary is over 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
T. A. Fanning	5 Times	10 Times
A. P. Beattie	3 Times	6 Times
W. P. Bowers	3 Times	6 Times
S. E. Kuczynski	3 Times	6 Times
C. D. McCrary	1.5 Times	3 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement and newly-promoted officers, including Messrs. Fanning, Beattie, and Kuczynski, 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 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 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. For tax purposes, in order to ensure that annual performance-based compensation is fully deductible under Section 162(m) of the Code, in February 2012, the Compensation

Committee approved a formula that represented a maximum annual performance-based compensation amount payable. For 2012 performance, the Compensation Committee used (for annual performance-based compensation) negative discretion from the formula amount to determine the actual payouts pursuant to the methodologies described above. 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.

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.

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, 2012 and in this Proxy Statement. The Board of Directors approved that recommendation.

Members of the Compensation Committee:

Veronica M. Hagen, Chair
Henry A. Clark III
H. William Habermeyer, Jr.
William G. Smith, Jr.

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2010, 2011, and 2012 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	2012	1,114,846	—	3,037,473	2,025,000	2,078,158	4,712,413	67,458	13,035,348
Chairman,	2011	1,064,399	—	2,246,974	1,498,000	2,459,181	2,423,524	62,164	9,754,242
President,	2010	809,892	—	782,054	521,378	1,951,986	1,902,932	50,909	6,019,151
and Chief									
Executive									
Officer									
Art P. Beattie	2012	615,378	—	773,330	515,558	737,382	2,747,374	34,352	5,423,374
Executive Vice	2011	552,614	—	684,365	456,248	772,343	1,523,479	83,471	4,072,520
President and Chief	2010	385,211	53,500	125,040	83,366	635,909	1,135,073	530,681	2,948,780
Financial Officer									
W. Paul Bowers	2012	739,587	42	1,003,813	669,227	1,013,366	2,024,578	50,830	5,501,443
President and Chief	2011	715,845	—	801,340	534,225	1,232,850	1,317,429	42,052	4,643,741
Executive Officer,	2010	652,189	—	1,948,515	520,654	1,276,879	884,674	43,636	5,326,547
Georgia Power									
Stephen E.	2012	640,289	—	617,967	411,997	619,288	77,727	101,886	2,469,154
Kuczynski	2011	312,500	75,000	799,990	999,997	328,067	—	218,811	2,734,365
President and Chief									
Executive Officer,									
Southern Nuclear									
Charles D. McCrary	2012	777,167	—	3,054,840	703,232	1,028,204	2,437,448	44,722	8,045,613
President and Chief	2011	752,219	—	842,058	561,369	1,424,219	1,733,395	44,676	5,357,936
Executive Officer,	2010	704,520	—	779,192	519,461	1,534,615	919,066	42,285	4,499,139
Alabama Power									

Column (a)

Mr. Kuczynski was not an executive officer of the Company prior to 2011.

Column (d)

This column reports the value of a non-cash safety award. All employees of Georgia Power, including Mr. Bowers, with a perfect individual safety record in the prior year, earned a safety award.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2012. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2012. 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, 2014. 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 2012 to Messrs. Fanning, Beattie, Bowers, McCrary, and Kuczynski, assuming that the highest level of performance is achieved, is $6,074,946, $1,546,660, $2,007,626, $2,109,662, and $1,235,934, respectively (200% of the amount shown in the table). For Mr. McCrary, the amount in column (e) also includes the grant date fair value ($2,000,009) of restricted stock units granted in 2012 as described 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 aggregate of the payouts under the annual Performance Pay Program and the Performance Dividend Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended on December 31, 2012. The amount reported for performance dividends is the amount earned at the end of the four-year performance-measurement period of January 1, 2009 through December 31, 2012. These awards were granted by the Compensation Committee in 2009 and were paid on stock options granted prior to 2010 that were outstanding at the end of 2012. As described in the CD&A, the Performance Dividend Program was eliminated by the Compensation Committee in 2010 and replaced with performance shares. The payout reported in column (g) is the third and final payout in the three-year transition period as described in the CD&A. The Performance Pay Program, the Performance Dividend Program, and performance shares are described in detail in the CD&A.

The amounts paid under each program to the named executive officers are shown below.

	Annual Performance-Based Compensation ($)	Performance Dividends ($)	Total ($)
T. A. Fanning	1,837,125	241,033	2,078,158
A. P. Beattie	669,600	67,782	737,382
W. P. Bowers	758,457	254,909	1,013,366
S. E. Kuczynski	619,288	—	619,288
C. D. McCrary	890,761	137,443	1,028,204

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, 2010, 2011, and 2012. 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.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2012, 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, 2011 and December 31, 2012 are:

- Discount rate for the Pension Plan was decreased to 4.30% as of December 31, 2012 from 5.00% as of December 31, 2011, and
- Discount rate for the supplemental pension plans was decreased to 3.70% as of December 31, 2012 from 4.65% as of December 31, 2011.

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 the Georgia Power safety award; employer contributions in 2012 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 2012 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 2012 are itemized below.

	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
T. A. Fanning	10,593	—	12,750	44,115	67,458
A. P. Beattie	4,741	—	10,977	18,634	34,352
W. P. Bowers	13,291	31	12,539	24,969	50,830
S. E. Kuczynski	62,588	10,694	8,699	19,905	101,886
C. D. McCrary	6,891	—	10,945	26,886	44,722

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 the 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 2012, Mr. Kuczynski received relocation-related benefits in the amount of $51,797 in connection with his 2011 relocation from St. Charles, Illinois to Birmingham, Alabama. 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 the Company's relocation policy, tax assistance is provided on the taxable relocation benefits. If Mr. Kuczynski terminates within two years of his relocation, these amounts must be repaid.

Personal Use of Corporate-Owned Aircraft. The Company owns 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.

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 2012

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2012 by the Compensation Committee.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($) (l)
T. A. Fanning		12,938	1,293,750	2,587,500							
	2/13/2012				723	72,338	144,676				3,037,473
	2/13/2012								597,345	44.42	2,025,000
A. P. Beattie		4,715	471,549	943,098							
	2/13/2012				184	18,417	36,834				773,330
	2/13/2012								152,082	44.42	515,558
W. P. Bowers		5,577	557,689	1,115,378							
	2/13/2012				239	23,906	47,812				1,003,813
	2/13/2012								197,412	44.42	669,227
S. E. Kuczynski		4,184	418,438	836,876							
	2/13/2012				147	14,717	29,434				617,967
	2/13/2012								121,533	44.42	411,997
C. D. McCrary		5,860	586,027	1,172,054							
	2/13/2012				251	25,121	50,242				1,054,831
	2/13/2012								207,443	44.42	703,232
	5/22/2012							43,908			2,000,009

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2012 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.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2012, 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 2012 through 2014 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Column (i)

This column reflects the number of restricted stock units granted to Mr. McCrary on the grant date 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 2012, 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 2012. 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 restricted stock units, the value is based on the closing price of Common Stock on the grant date. The assumptions used in calculating these amounts are discussed in Note 8 to the Financial Statements.

OUTSTANDING EQUITY AWARDS AT 2012 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, 2012.

	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	100,158	—	35.78	2/18/2018				
	254,302	—	31.39	2/16/2019				
	155,868	77,934	31.17	2/15/2020				
	153,641	307,282	37.97	2/14/2021				
	—	597,345	44.42	2/13/2022				
							124,936	5,348,510
							144,676	6,193,580
A. P. Beattie	21,558	—	32.70	2/18/2015				
	20,138	—	33.81	2/20/2016				
	22,550	—	36.42	2/19/2017				
	21,779	—	35.78	2/18/2018				
	13,654	—	31.39	2/16/2019				
	24,923	12,461	31.17	2/15/2020				
	46,795	93,589	37.97	2/14/2021				
	—	152,082	44.42	2/13/2022				
							38,052	1,629,006
							36,834	1,576,864

OUTSTANDING EQUITY AWARDS AT 2012 FISCAL YEAR-END (continued)

	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)
W. P. Bowers	60,576	—	32.70	2/18/2015				
	67,517	—	33.81	2/20/2016				
	70,680	—	36.42	2/19/2017				
	85,151	—	35.78	2/18/2018				
	90,942	—	31.39	2/16/2019				
	155,651	77,826	31.17	2/15/2020				
	54,793	109,584	37.97	2/14/2021				
	—	197,412	44.42	2/13/2022				
							44,556	1,907,442
							47,812	2,046,832
					36,257	1,552,162		
S. E. Kuczynski	110,742	221,483	40.14	7/11/2021				
	—	121,533	44.42	2/13/2022				
							29,434	1,260,070
					14,880	637,013		
C. D. McCrary	102,333	—	36.42	2/19/2017				
	99,789	—	35.78	2/18/2018				
	—	77,647	31.17	2/15/2020				
	57,577	115,152	37.97	2/14/2021				
	—	207,443	44.42	2/13/2022				
							46,820	2,004,364
							50,242	2,150,860
					44,872	1,920,970		

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2005 through 2009 with expiration dates from 2015 through 2019 were fully vested as of December 31, 2012. The options granted in 2010, 2011, and 2012 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2010	February 15, 2020	February 15, 2013
2011	February 14, 2021	February 14, 2014
2012	February 13, 2022	February 13, 2015

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, 2012. The value in column (g) is based on the Common Stock closing price on December 31, 2012 ($42.81). The restricted stock units for Messrs. Bowers and McCrary vest on July 27, 2013 and December 31, 2014, respectively. The restricted stock units for Mr. Kuczynski vest in part on July 11, 2013, with the remainder vesting on July 11, 2015. See further discussion of restricted stock in the CD&A.

Columns (h) and (i)

In accordance with SEC rules, column (h) reflects the maximum number of performance shares that can be earned at the end of each three-year performance period (December 31, 2013 and 2014) that were granted in 2011 and 2012, respectively.

The performance shares granted for the 2010 through 2012 performance period vested on December 31, 2012 and are shown in the Option Exercises and Stock Vested in 2012 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, 2012 ($42.81). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. See further discussion of performance shares in the CD&A.

OPTION EXERCISES AND STOCK VESTED IN 2012

	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)
T. A. Fanning	275,617	2,933,605	35,041	1,500,105
A. P. Beattie	—	—	5,603	239,864
W. P. Bowers	—	—	34,992	1,498,008
S. E. Kuczynski	—	—	6,240	294,466
C. D. McCrary	343,266	4,836,619	34,912	1,494,583

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2012 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 2010 through 2012 performance period that vested on December 31, 2012. 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 ($42.81).

Because Mr. Kuczynski was not an employee of the Southern Company system when performance shares were awarded in 2010, column (d) does not reflect any vested performance shares for Mr. Kuczynski. Certain restricted stock units vested on July 11, 2012 and are reflected in column (d) for Mr. Kuczynski. The value of the restricted stock units as shown 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 ($47.19).

PENSION BENEFITS AT 2012 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	31.0	1,063,266	—
	Supplemental Benefit Plan (Pension-Related)	31.0	7,694,320	—
	Supplemental Executive Retirement Plan	31.0	4,312,702	—
A. P. Beattie	Pension Plan	35.92	1,371,551	—
	Supplemental Benefit Plan (Pension-Related)	35.92	3,600,142	—
	Supplemental Executive Retirement Plan	35.92	2,184,426	—
W. P. Bowers	Pension Plan	32.67	1,133,147	—
	Supplemental Benefit Plan (Pension-Related)	32.67	4,680,876	—
	Supplemental Executive Retirement Plan	32.67	1,803,155	—
S. E. Kuczynski	Pension Plan	0.58	17,155	—
	Supplemental Benefit Plan (Pension-Related)	0.58	32,201	—
	Supplemental Executive Retirement Plan	0.58	28,371	—
C. D. McCrary	Pension Plan	38.0	1,628,741	—
	Supplemental Benefit Plan (Pension-Related)	38.0	7,637,668	—
	Supplemental Executive Retirement Plan	38.0	2,538,824	—

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 2012 was $250,000.

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, 2012, all of the named executive officers are retirement-eligible except 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, 2012, all of the named executive officers are vested in their Pension Plan benefits except Mr. Kuczynski. 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 in the section entitled "Potential Payments upon Termination or Change in Control."

The following assumptions were used in the present value calculations:

- Discount rate - 4.30% Pension Plan and 3.70% supplemental plans as of December 31, 2012,
- Retirement date - Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement - RP2000 Combined Healthy 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: 40% single life annuity; 40% level income annuity; 10% joint and 50% survivor annuity; and 10% 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 4.50% 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.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2012 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	363,276	44,115	43,645	—	2,312,749
A. P. Beattie	—	18,634	9,526	—	449,549
W. P. Bowers	—	24,969	97,939	—	3,174,152
S. E. Kuczynski	—	19,905	(1,026)	—	18,879
C. D. McCrary	—	26,886	3,602	—	1,541,910

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 2012, the rate of return in the Stock Equivalent Account was -3.4%, which was the Company's total shareholder return for 2012.

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 2012 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 2012. 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 2012 were the amounts paid for performance under the annual Performance Pay Program and the Performance Dividend Program that were earned as of December 31, 2011 but not payable until the first quarter of 2012. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2012 but not payable until early 2013. 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 2012 and previously reported ($)	Employer Contributions under the SBP prior to 2012 and previously reported ($)	Total ($)
T. A. Fanning	1,249,703	279,013	1,528,716
A. P. Beattie	34,781	22,839	57,620
W. P. Bowers	1,536,730	92,543	1,629,273
S. E. Kuczynski	0	0	0
C. D. McCrary	489,924	321,584	811,508

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers 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, 2012 and assumes that the price of Common Stock is the closing market price on December 31, 2012.

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 terminate before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Performance Dividend Program	Paid year of retirement plus two additional years.	Forfeit.	Forfeit.	Payable until options expire or exercised.	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 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.
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 benefit administration committee's discretion.	Same as Retirement.
Supplemental Benefit Plan - 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	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.
Performance Dividend 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 greater of target or actual performance level.	Same as Company Change-in-Control I.	Prorated at greater of actual or target performance level.	If not otherwise eligible for payment, if the program is still in effect, greater of actual or target performance level for year of severance only.

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
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.
Restricted Stock Units	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.	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, 2012.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2012 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, 2012 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, 2012 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, Mr. Kuczynski was not retirement-eligible as of December 31, 2012.

		Retirement ($)	**Resignation or Involuntary Termination**	**Death (payments to a spouse) ($)**
T. A. Fanning	Pension	6,767	treated as retiring	4,566
	SBP-P	926,023	treated as retiring	926,023
	SERP	519,040	treated as retiring	519,040
A. P. Beattie	Pension	8,986	treated as retiring	5,279
	SBP-P	423,760	treated as retiring	423,760
	SERP	257,121	treated as retiring	257,121
W. P. Bowers	Pension	7,233	treated as retiring	4,815
	SBP-P	563,558	treated as retiring	563,558
	SERP	217,092	treated as retiring	217,092
S. E. Kuczynski	Pension	—	—	—
	SBP-P	—	—	—
	SERP	—	—	—
C. D. McCrary	Pension	10,803	treated as retiring	5,659
	SBP-P	860,509	treated as retiring	860,509
	SERP	286,040	treated as retiring	286,040

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, 2012 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	9,260,230	5,190,402	14,450,632
A. P. Beattie	4,237,600	2,571,211	6,808,811
W. P. Bowers	5,635,584	2,170,924	7,806,508
S. E. Kuczynski	—	—	—
C. D. McCrary	8,605,088	2,860,402	11,465,490

The pension benefit amounts in the tables above were calculated as of December 31, 2012 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 3.18% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2012 is the greater of target or actual performance. Because actual payouts for 2012 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the Summary Compensation Table.

Performance Dividends

Because the assumed termination date is December 31, 2012, there is no additional amount that would be payable other than what was reported in the Summary Compensation Table. As described in the Traditional Termination Events chart, there is some continuation of benefits under the Performance Dividend Program for retirees. However, under a change-in-control-related event, performance dividends are payable at the greater of target performance or actual performance. For the 2009 through 2012 performance-measurement period, actual performance was less than target-level performance. The chart below shows the additional amounts that would have been paid upon a change in control.

	Additional Performance Dividends ($)
T. A. Fanning	103,236
A. P. Beattie	29,032
W. P. Bowers	109,180
S. E. Kuczynski	—
C. D. McCrary	58,868

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, 2012. The value of performance shares and restricted stock units is calculated using the closing price of Common Stock on December 31, 2012. 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	982,561	134,806	—	1,646,530	134,806	—	14,331,607
A. P. Beattie	258,132	37,443	—	429,529	37,443	—	3,569,866
W. P. Bowers	384,822	46,184	36,257	970,132	46,184	36,257	10,351,447
S. E. Kuczynski	343,016	14,717	14,880	453,758	14,717	14,880	2,154,088
C. D. McCrary	400,242	48,531	44,872	659,941	48,531	44,872	7,093,826

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 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 Mr. Kuczyinski two years of healthcare insurance premiums is less than $20,000 per year.

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 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.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2012 in connection with a change in control.

	Severance Amount ($)
T. A. Fanning	7,256,250
A. P. Beattie	2,200,562
W. P. Bowers	2,602,548
S. E. Kuczynski	2,124,375
C. D. McCrary	2,734,792

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 2012, none of the Company's executive officers served on the Board of Directors of any entities whose executive officers serve on the Compensation Committee.

Other Information

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

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.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Mr. Donald M. James is the Chief Executive Officer of Vulcan Materials Company. During 2012, subsidiaries of the Company purchased approximately $10,838,355 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 Georgia/North Florida Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc. During 2012, subsidiaries of the Company made payments of approximately $1,477,084 to certain subsidiaries of SunTrust Banks, Inc., substantially related to aircraft leases.

During 2012, 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 $1,263,177 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.

In 2012, Ms. Mary V. Story, the sister-in-law of Ms. Susan N. Story, a former executive officer of the Company, was employed by the Southern Company system as an advertising and marketing communications manager and received compensation of $340,852.

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.

APPENDIX A

AMENDMENT TO THE COMPANY'S BY-LAWS FOR RATIFICATION

The text of the amendment, marked to show changes to the prior Section 15 of the By-Laws, is set forth as follows:

15. A person being a full-time executive employee of the Corporation or any of its subsidiaries when first elected a director of the Corporation (an "employee-director") shall not be eligible to serve as a director when not an executive employee, whether by reason of resignation, retirement or other cause.~~; and a person not an employee-director shall not be eligible for election or re-election as a director of the Corporation after his 70th birthday.~~

Any employee-director not eligible to serve as a director by reason of the foregoing provision shall be eligible to serve as an advisory director, as hereinafter provided for in Section 24 of these By-Laws, until his 70th birthday. ~~The foregoing provisions with respect to the eligibility of a person not an employee-director to serve as a director shall not apply to any person so long as such person shall serve as a member of the Independent Litigation Committee established and designated by the Board of Directors on September 17, 1986.~~

In addition to the powers and authorities expressly conferred upon it by statute, by the Certificate of Incorporation and by these By-Laws, the Board of Directors may exercise all such powers of the Corporation and do all such lawful acts and things as may be done by the Corporation as are not by statute or by the Certificate of Incorporation or by these By-Laws directed or required to be exercised or done by the stockholders.

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APPENDIX B

PROPOSED AMENDMENT TO ARTICLE ELEVENTH OF CERTIFICATE OF INCORPORATION

The text of the proposed amendment to Article Eleventh of the Certificate of Incorporation, marked to show changes to the current Article Eleventh, is set forth as follows:

ELEVENTH: The corporation reserves the right to increase or decrease its authorized capital stock, or any class or series thereof, or to reclassify the same, and to amend, alter, change or repeal any provision contained in the Certificate of Incorporation or in any amendment thereto, in the manner now or hereafter prescribed by law, and all rights conferred upon stockholders in said Certificate of Incorporation or any amendment thereto are granted subject to this reservation; provided, however, that the corporation shall not, unless authorized by the affirmative vote in favor thereof of the holders of at least ~~two-thirds~~ a majority of the issued and outstanding common stock of the corporation given at any annual meeting of stockholders or at any special meeting called for that purpose, ~~(a)~~ authorize or create any class of stock preferred as to dividends or assets over the common stock or reclassify the common stock or change the issued shares of common stock into the same or a greater or less number of shares of common stock either with or without par value or reduce the par value of the common stock~~, or (b) amend, alter, change or repeal subdivision (2) of Article Ninth, Article Twelfth, this provisio or any provision contained in the Certificate of Incorporation or in any amendment thereto which provides for the vote of the holders of at least two-thirds of the issued and outstanding common stock~~.

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APPENDIX C

PROPOSED AMENDMENT TO ARTICLE THIRTEENTH OF THE CERTIFICATE OF INCORPORATION

The text of the proposed amendment to Section 1 of Article Thirteenth of the Certificate of Incorporation, marked to show changes to the current Section 1 of Article Thirteenth, is set forth as follows:

(1) A. In addition to any affirmative vote required by law or the Certificate of Incorporation (any other provision of the Certificate of Incorporation notwithstanding), and except as otherwise expressly provided in subdivision (2) of this Article Thirteenth:

(a) any merger or consolidation of the corporation or any Subsidiary (as hereinafter defined) with (i) any Interested Stockholder (as hereinafter defined) or (ii) any other corporation (whether or not itself an Interested Stockholder) which is, or after such merger or consolidation would be, an Affiliate (as hereinafter defined) of an Interested Stockholder; or

(b) any sale, lease, license, exchange, mortgage, pledge, transfer or other disposition (in one transaction or a series of transactions) to or with any Interested Stockholder or any Affiliate of any Interested Stockholder of any assets of the corporation or any Subsidiary having an aggregate Fair Market Value (as hereinafter defined) of $100,000,000 or more; or

(c) the issuance or transfer by the corporation or any Subsidiary (in one transaction or a series of transactions) of any securities of the corporation or any Subsidiary to any Interested Stockholder or any Affiliate of any Interested Stockholder having an aggregate Fair Market Value of $100,000,000 or more; or

(d) the adoption of any plan or proposal for the liquidation or dissolution of the corporation proposed by or on behalf of any Interested Stockholder or any Affiliate of any Interested Stockholder; or

(e) any reclassification of securities (including any reverse stock split), or recapitalization of the corporation, or any merger or consolidation of the corporation with any of its Subsidiaries or any other transaction (whether or not with or into or otherwise involving any Interested Stockholder) which has the effect, directly or indirectly, of increasing the proportionate share of the outstanding shares of any class of equity or convertible securities of the corporation or any Subsidiary which is directly or indirectly owned by any Interested Stockholder or any Affiliate of any Interested Stockholder;

shall require the affirmative vote of the holders of at least (i) ~~seventy-five~~ 66 2/3 per centum of the issued and outstanding capital stock of the corporation having voting powers (the "Voting Stock"), voting together as a single class, and (ii) a majority of the issued and outstanding Voting Stock beneficially owned by persons other than such Interested Stockholder, voting together as a single class, given at any annual meeting of stockholders or at any special meeting called for that purpose. Such affirmative vote shall be required notwithstanding the fact that no vote may be required, or that a lesser percentage may be specified, by law, by any other provision of the Certificate of Incorporation or in any agreement with any national securities exchange or otherwise.

B. The term "Business Combination" as used in this Article Thirteenth shall mean any transaction which is referred to in any one or more of clauses (a) through (e) of paragraph A of this subdivision (1).

The text of the proposed amendment to Section 6 of Article Thirteenth of the Certificate of Incorporation, marked to show changes to the current Section 6 of Article Thirteenth, is set forth as follows:

(6) Notwithstanding any other provisions of the Certificate of Incorporation or the By-Laws of the corporation (and notwithstanding the fact that a lesser percentage may be specified by law, the Certificate of Incorporation or the By-Laws of the corporation), the affirmative vote of the holders of at least (i) ~~seventy-five~~ 66 2/3 per centum of the issued and outstanding Voting Stock, voting together as a single class, and (ii) a

majority of the issued and outstanding Voting Stock beneficially owned by persons other than an Interested Stockholder, voting together as a single class, given at any annual meeting of stockholders or at any special meeting called for that purpose, shall be required to amend, alter, change or repeal, or adopt any provisions inconsistent with, this Article Thirteenth; provided, however, that the foregoing provisions of this subdivision (6) shall not apply to, and such vote shall not be required for, any such amendment, alteration, change, repeal or adoption approved by a majority of the Disinterested Directors, and any such amendment, alteration, change, repeal or adoption so approved shall require only such vote, if any, as is required by law, any other provision of the Certificate of Incorporation or the By-Laws of the corporation.

APPENDIX D

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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APPENDIX E

SOUTHERN COMPANY

2012 ANNUAL REPORT

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SOUTHERN COMPANY COMMON STOCK AND DIVIDEND INFORMATION

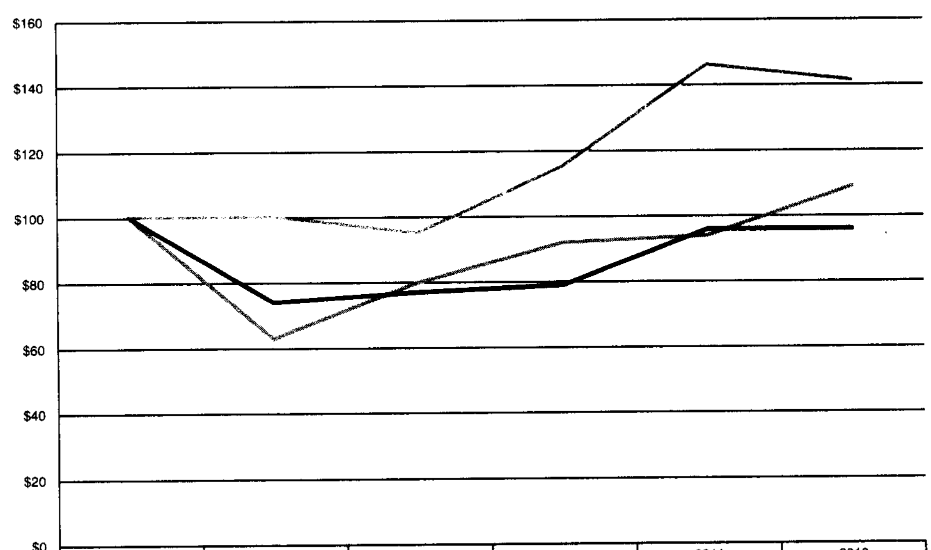
The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low	Dividend
2012			
First Quarter	$46.06	$ 43.71	$ 0.4725
Second Quarter	48.45	44.22	0.4900
Third Quarter	48.59	44.64	0.4900
Fourth Quarter	47.09	41.75	0.4900
2011			
First Quarter	$38.79	$ 36.51	$ 0.4550
Second Quarter	40.87	37.43	0.4725
Third Quarter	43.09	35.73	0.4725
Fourth Quarter	46.69	41.00	0.4725

On March 25, 2013, Southern Company had 148,651 registered stockholders.

FIVE-YEAR CUMULATIVE PERFORMANCE GRAPH

This performance graph compares the cumulative total shareholder return on the Company's common stock (SO) with the Standard & Poor's Electric Utility Index (S5ELUT) and the Standard & Poor's 500 index (SPX) for the past five years. The graph assumes that $100 was invested on December 31, 2007 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.



	2007	2008	2009	2010	2011	2012
SPX	100	63	80	92	94	109
S5ELUT	100	74	77	79	96	96
SO	100	100	95	115	146	141

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2012 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* 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, 2012.

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, 2012. 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

February 27, 2013

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, 2012 and 2011, 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, 2012. We also have audited the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* 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 E-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 E-37 to E-103) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2013

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – and Southern Power Company (Southern Power), and other direct and indirect subsidiaries (together, the Southern Company system). 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 given economic conditions, 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, fuel, capital expenditures, including new plants, and restoration following major storms. Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants, including renewable energy projects, and by entering into power purchase agreements (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, 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 fossil/hydro 2012 Peak Season EFOR was better than the target, excluding the impact of Hurricane Isaac in August 2012. 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 performance for 2012 was better than the target for these reliability measures.

Southern Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
System Customer Satisfaction	**Top quartile in customer surveys**	**Top quartile**
Peak Season System EFOR — fossil/hydro*	**4.99% or less**	**2.81%**
Basic EPS	**$2.58 — $2.70**	**$2.70**
EPS, excluding the MC Asset Recovery insurance settlement**		**$2.68**

*Excluding impact of Hurricane Isaac

**Southern Company filed an insurance claim in 2009 to recover a portion of the MC Asset Recovery settlement and received a nontaxable $25 million payment from its insurance provider on June 14, 2012. Additionally, legal fees related to this insurance settlement totaled approximately $6 million. As a result, the net reduction to expense for this insurance settlement was approximately $19 million. Southern Company management uses the non-generally accepted accounting principles (GAAP) measure of EPS, excluding the MC Asset Recovery insurance settlement, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of this non-GAAP measure of earnings and EPS excluding the MC Asset Recovery insurance settlement is useful for investors because it provides earnings information that is consistent with the historical and ongoing business activities of the Company. The presentation of this information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.35 billion in 2012, an increase of $147 million, or 6.7%, from the prior year. The increase was primarily the result of lower operations and maintenance expenses resulting from cost containment efforts in 2012, increases in revenues associated with the elimination of a tax-related adjustment under Alabama Power's rate structure, an increase related to retail revenue rate effects at Georgia Power, and an increase in revenues due to increases in retail base rates at Gulf Power. Also contributing to the increase were higher capacity revenues and an increase in retail sales growth. The increases were partially offset by milder weather and an increase in depreciation on additional plant in service related to new generation, transmission, distribution, and environmental projects.

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.20 billion in 2011, an increase of $228 million, or 11.5%, from the prior year. The increase was primarily the result of increases in Georgia Power's retail base revenues as authorized under the 2010 Alternative Rate Plan for the years 2011 through 2013 (2010 ARP) and the recovery of financing costs through the Nuclear Construction Cost Recovery (NCCR) tariff. Also contributing to the increase were increases in energy and capacity revenues at Southern Power and a reduction in operations and maintenance expenses primarily at Alabama Power. The 2011 increase was partially offset by decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, a decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power, a decrease in wholesale revenues primarily at Alabama Power, and a reduction in allowance for funds used during construction (AFUDC) equity. Net income after dividends on preferred and preference stock of subsidiaries was $1.98 billion in 2010.

Basic EPS was $2.70 in 2012, $2.57 in 2011, and $2.37 in 2010. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.67 in 2012, $2.55 in 2011, and $2.36 in 2010. EPS for 2012 was negatively impacted by $0.05 per share as a result of an increase in the average shares outstanding.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $1.9425 in 2012, $1.8725 in 2011, and $1.8025 in 2010. In January 2013, Southern Company declared a quarterly dividend of 49.00 cents per share. This is the 261st consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 70% to 75% of net income. For 2012, the actual payout ratio was 71.9%, while the payout ratio of net income excluding the MC Asset Recovery insurance settlement was 72.5%.

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		
	2012	2011	2010
		(in millions)	
Electricity business	**$ 2,321**	$ 2,214	$ 1,991
Other business activities	**29**	(11)	(16)
Net income	**$ 2,350**	$ 2,203	$ 1,975

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	
	2012	**2012**	2011
		(in millions)	
Electric operating revenues	**$ 16,478**	**$ (1,109)**	$ 213
Fuel	**5,057**	**(1,205)**	(437)
Purchased power	**544**	**(64)**	45
Other operations and maintenance	**3,695**	**(147)**	(63)
Depreciation and amortization	**1,772**	**72**	205
Taxes other than income taxes	**912**	**13**	32
Total electric operating expenses	**11,980**	**(1,331)**	(218)
Operating income	**4,498**	**222**	431
Allowance for equity funds used during construction	**143**	**(10)**	(41)
Interest income	**22**	**3**	(3)
Interest expense, net of amounts capitalized	**820**	**17**	(30)
Other income (expense), net	**(57)**	**16**	(15)
Income taxes	**1,400**	**107**	179
Net income	**2,386**	**107**	223
Dividends on preferred and preference stock of subsidiaries	**65**	**—**	—
Net income after dividends on preferred and preference stock of subsidiaries	**$ 2,321**	**$ 107**	$ 223

Electric Operating Revenues

Details of electric operating revenues were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	**$ 15,071**	$ 14,791
Estimated change in —		
Rates and pricing	**296**	793
Sales growth (decline)	**39**	38
Weather	**(282)**	(279)
Fuel and other cost recovery	**(937)**	(272)
Retail — current year	**14,187**	15,071
Wholesale revenues	**1,675**	1,905
Other electric operating revenues	**616**	611
Electric operating revenues	**$ 16,478**	$ 17,587
Percent change	**(6.3)%**	1.2%

Retail revenues decreased $884 million, or 5.9%, in 2012 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 2012 was primarily due to increases in retail revenues at Georgia Power due to base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, as well as the collection of financing costs associated with the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) through the NCCR tariff and demand-side management programs effective January 1, 2012, as approved by the Georgia Public Service Commission (PSC), and the rate pricing effect of decreased customer usage. Also contributing to the increase were the elimination of a tax-related adjustment under Alabama Power's rate structure that was effective with October 2011 billings and higher revenues due to increases in retail base rates at Gulf Power. These increases were partially offset by lower contributions from market-driven rates from commercial and industrial customers at Georgia Power and decreased revenues under rate certificated new plant environmental (Rate CNP Environmental) at Alabama Power.

Retail revenues increased $280 million, or 1.9%, in 2011 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 2011 was primarily due to increases in Georgia Power's retail base revenues as authorized under the 2010 ARP, which became effective January 1, 2011. The increase in base revenues at Georgia Power also included the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Equity Funds Used During Construction" and "Interest Expense, Net of Amounts Capitalized" herein for additional information. Also contributing to the increase in rates and pricing in 2011 were revenues associated with Alabama Power's Rate CNP Environmental due to the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under Alabama Power's rate structure.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Retail Rate Adjustments" and "PSC Matters – Georgia Power – Rate Plans" herein 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, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts 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. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

In 2012, wholesale revenues decreased $230 million, or 12.1%, as compared to the prior year due to a $292 million decrease in energy sales primarily due to a reduction in the average price of energy and lower customer demand, partially offset by a $62 million increase in capacity revenues.

In 2011, wholesale revenues decreased $89 million, or 4.5%, as compared to the prior year due to decreased energy revenues. This decrease was primarily due to a decrease in wholesale revenues at Alabama Power due to the expiration of long-term unit power sales contracts in May 2010 and the capacity subject to those contracts being made available for retail service starting in June 2010, as well as lower energy and capacity revenues associated with the expiration of PPAs at Southern Power. The decrease was partially offset by higher energy and capacity revenues under new PPAs at Southern Power.

Revenues associated with PPAs and opportunity sales were as follows:

	2012	2011	2010
		(in millions)	
Other power sales —			
Capacity and other	$ 827	$ 767	$ 684
Energy	776	1,035	1,034
Total	$ 1,603	$ 1,802	$ 1,718

Kilowatt-hour (KWH) sales under unit power sales contracts decreased 65.2% and 69.6% in 2012 and 2011, respectively, as compared to the prior years. In addition, fluctuations in natural gas prices, which is the primary fuel source for unit power sales contracts, influence changes in energy sales. However, because the energy is generally sold at variable cost, fluctuations in energy sales have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2012	2011	2010
		(in millions)	
Unit power sales —			
Capacity	$ 55	$ 53	$ 136
Energy	17	50	140
Total	$ 72	$ 103	$ 276

Other Electric Revenues

Other electric revenues increased $5 million, or 0.8%, and $22 million, or 3.7%, in 2012 and 2011, respectively, as compared to the prior years. Other electric revenues increased in 2012 primarily due to an increase in rents from electric property. The 2011 increase in other electric revenues was primarily a result of an increase in transmission revenues at Georgia Power.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	2012	2011	2012	2011
	(in billions)				
Residential	50.4	(5.4)%	(7.7)%	1.1%	—%
Commercial	53.0	(1.6)	(2.9)	(0.2)	(0.3)
Industrial	51.7	0.2	3.2	0.2	3.3
Other	0.9	(1.8)	(0.8)	(1.4)	(0.7)
Total retail	156.0	(2.3)	(2.7)	0.4%	1.0%
Wholesale	27.6	(9.2)	(6.8)		
Total energy sales	183.6	(3.4)%	(3.4)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 3.6 billion KWHs in 2012 as compared to the prior year. This decrease was primarily the result of milder weather in 2012, partially offset by customer growth and an increase in customer demand primarily in the residential class. Retail energy sales decreased 4.5 billion KWHs in 2011 as compared to the prior year. This decrease was primarily the result of closer to normal weather in 2011 compared to 2010, partially offset by an increase in industrial KWH sales. Increased demand in the primary metals and fabricated metals sectors was the main contributor to the increase in industrial KWH sales. The number of customers in 2011 was flat when compared to 2010.

Wholesale energy sales decreased 2.8 billion KWHs in 2012 and 2.2 billion KWHs in 2011 as compared to the prior years. The decrease in wholesale energy sales in 2012 was primarily related to lower customer demand resulting from milder weather in 2012. The decrease in wholesale energy sales in 2011 was primarily related to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. This decrease was partially offset by increased energy sales under new PPAs at Southern Power.

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 generation and purchased power by the electric utilities were as follows:

	2012	2011	2010
Total generation *(billions of KWHs)*	**175**	186	196
Total purchased power *(billions of KWHs)*	**16**	12	10
Sources of generation *(percent)* —			
Coal	**38**	52	58
Nuclear	**18**	16	15
Gas	**42**	30	25
Hydro	**2**	2	2
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.96**	4.02	3.93
Nuclear	**0.83**	0.72	0.63
Gas	**2.86**	3.89	4.27
Average cost of fuel, generated *(cents per net KWH)*	**2.93**	3.43	3.50
Average cost of purchased power *(cents per net KWH)* *	**4.45**	6.32	6.98

* Average cost of purchased power includes fuel purchased by the electric utilities for tolling agreements where power is generated by the provider.

In 2012, total fuel and purchased power expenses were $5.6 billion, a decrease of $1.3 billion, or 18.5%, as compared to the prior year. This decrease was primarily the result of a $1.0 billion decrease in the average cost of fuel and purchased power and a $519 million decrease in the volume of KWHs generated as a result of milder weather in 2012, partially offset by a $270 million increase in the volume of KWHs purchased.

In 2011, total fuel and purchased power expenses were $6.9 billion, a decrease of $392 million, or 5.4%, as compared to the prior year. This decrease was primarily the result of a $349 million decrease in the volume of KWHs generated and a $206 million decrease in the average cost of fuel and purchased power, partially offset by a $163 million increase in the volume of KWHs purchased.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

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

Fuel

In 2012, fuel expense was $5.1 billion, a decrease of $1.2 billion, or 19.2%, as compared to the prior year. The decrease was primarily due to a 26.5% decrease in the average cost of natural gas per KWH generated, a higher percentage of generation from lower-cost natural gas-fired resources, and lower customer demand mainly due to milder weather in 2012.

In 2011, fuel expense was $6.3 billion, a decrease of $437 million, or 6.5%, as compared to the prior year. The decrease was primarily due to an 8.9% decrease in the average cost of natural gas per KWH generated and lower demand primarily due to closer to normal weather in 2011 compared to 2010.

Purchased Power

In 2012, purchased power expense was $544 million, a decrease of $64 million, or 10.5%, as compared to the prior year. The decrease was due to a 29.6% decrease in the average cost per KWH purchased, partially offset by a 35.1% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available.

In 2011, purchased power expense was $608 million, an increase of $45 million, or 8.0%, as compared to the prior year. The increase was due to a 23.9% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available, partially offset by a 9.5% decrease 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 were $3.7 billion and $3.8 billion, decreasing $147 million, or 3.8%, and $63 million, or 1.6%, in 2012 and 2011, respectively, as compared to the prior years. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants decreased $110 million in 2012 and increased $2 million in 2011 as compared to the prior years. Production expenses fluctuate from year to year due to variations in outage schedules and changes in the cost of labor and materials. Other production expenses decreased in 2012 primarily due to a decrease in scheduled outage and maintenance costs and commodity and labor costs, which was primarily the result of cost containment efforts to offset the effect of milder weather in 2012. Also contributing to the decrease was a $35 million decrease at Mississippi Power related to the expiration of the operating lease for Plant Daniel Units 3 and 4, which was offset by a $35 million increase at Alabama Power primarily related to a change in the nuclear maintenance outage accounting process associated with routine refueling activities, as approved by the Alabama PSC in 2010. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information. Other production expenses increased in 2011 mainly due to a $29 million increase in commodity and labor costs and a $26 million increase in outage and maintenance costs. These increases were largely offset by a decrease in nuclear outage expense at Alabama Power, primarily related to the change in the nuclear maintenance outage accounting process. As a result, Alabama Power did not recognize any nuclear maintenance outage expenses in 2011, reducing nuclear production expense by approximately $50 million as compared to 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Nuclear Outage Accounting Order" herein for additional information.

Transmission and distribution expenses decreased $75 million and $80 million in 2012 and 2011, respectively, as compared to the prior years. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules and normal changes in the cost of labor and materials. Transmission and distribution expenses decreased in 2012 primarily due to cost containment efforts to offset the effects of the milder weather in 2012 and a reduction in accruals at Alabama Power to the natural disaster reserve (NDR). Transmission and distribution expenses decreased in 2011 primarily due to reductions in spending related to vegetation management and a reduction in accruals to the NDR at Alabama Power. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information.

Customer accounts, sales, and service expenses decreased $20 million in 2012 and increased $33 million in 2011 as compared to the prior years. Customer accounts, sales, and service expenses decreased in 2012 primarily due to a decrease in uncollectible account expense at Georgia Power. Customer accounts, sales, and service expenses increased in 2011 primarily due to a $24 million increase in customer service expense primarily related to new demand side management programs at Georgia Power and a $9 million increase in records and collection expense.

Administrative and general expenses increased $58 million in 2012 and decreased $18 million in 2011 as compared to the prior years. Administrative and general expenses increased in 2012 primarily as a result of an increase in pension costs. Administrative and general expenses decreased in 2011 primarily as a result of a $10 million decrease in property insurance cost and a $7 million decrease in injuries and damages reserve costs.

Depreciation and Amortization

Depreciation and amortization increased $72 million, or 4.2%, in 2012 as compared to the prior year primarily as a result of additional plant in service related to new generation at Georgia Power's Plant McDonough-Atkinson Units 4 and 5, additional plant in service at Southern Power, as well as transmission, distribution, and environmental projects, partially offset by amortization of the regulatory liability for state income tax credits at Georgia Power as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

Depreciation and amortization increased $205 million, or 13.7%, in 2011 as compared to the prior year primarily as a result of a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC and additional depreciation on plant in service related to environmental, transmission, and distribution projects. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information regarding Georgia Power's cost of removal amortization.

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

Taxes Other Than Income Taxes

Taxes other than income taxes increased $13 million, or 1.4%, in 2012 as compared to the prior year primarily due to increases in property taxes, partially offset by a decrease in municipal franchise fees. Taxes other than income taxes increased $32 million, or 3.7%, in 2011 compared to the prior year primarily due to increases in property taxes and municipal franchise fees at Georgia Power and increases in state and municipal public utility license tax bases at Alabama Power. Increases in franchise fees are associated with increases in revenues from energy sales.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $10 million, or 6.5%, in 2012 as compared to the prior year primarily due to the completion of Georgia Power's Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively, partially offset by increases in construction work in progress (CWIP) related to Mississippi Power's integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi (Kemper IGCC), which began construction in 2010.

AFUDC equity decreased $41 million, or 21.1%, in 2011 as compared to the prior year primarily due to the inclusion of Georgia Power's construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized, with an offsetting increase in operating revenues through the NCCR tariff. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information. Also contributing to the decrease was the completion of construction projects related to environmental mandates at Alabama Power. The 2011 decrease was partially offset by CWIP related to Mississippi Power's Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Total interest charges and other financing costs increased $17 million, or 2.1%, in 2012 as compared to the prior year primarily due to a $23 million reduction in interest expense in 2011 at Georgia Power resulting from the settlement of litigation with the Georgia Department of Revenue (DOR), a decrease in AFUDC debt at Georgia Power due to the completion of Plant McDonough-Atkinson Units 4 and 5, and a net increase in interest expense related to senior notes and other long-term debt. The increases were partially offset by a decrease in interest expense on existing variable rate pollution control revenue bonds, an increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC at Mississippi Power, and a decrease related to the conclusion of certain state and federal income tax audits.

Total interest charges and other financing costs decreased $30 million, or 3.6%, in 2011 as compared to the prior year primarily due to a reduction of $23 million in interest expense at Georgia Power related to the settlement of litigation with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds at Georgia Power. The decrease was partially offset by a reduction in AFUDC debt at Georgia Power due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base.

Other Income (Expense), Net

Other income (expense), net increased $16 million, or 21.9%, in 2012 and decreased $15 million, or 25.9%, in 2011 as compared to the prior years primarily due to a make-whole premium payment in connection with the early redemption of senior notes at Southern Power in 2011.

Income Taxes

Income taxes increased $107 million, or 8.3%, in 2012 as compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.

Income taxes increased $179 million, or 16.1%, in 2011 as compared to the prior year primarily due to higher pre-tax earnings, a decrease in 2010 in uncertain tax positions at Georgia Power related to state income tax credits, and a reduction in AFUDC equity, which is non-taxable.

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. invests in various projects, including leveraged lease projects, and Southern Communications Services, Inc. (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	
	2012	2012	2011
		(in millions)	
Operating revenues	$ 59	$ (11)	$ (12)
Other operations and maintenance	96	—	(9)
MC Asset Recovery litigation settlement	(19)	(19)	—
Depreciation and amortization	15	(2)	(1)
Taxes other than income taxes	2	—	—
Total operating expenses	94	(21)	(10)
Operating income (loss)	(35)	10	(2)
Interest income	18	16	—
Equity in income (losses) of unconsolidated subsidiaries	(2)	—	—
Leveraged lease income (losses)	21	(4)	7
Other income (expense), net	—	11	6
Interest expense	39	(15)	(8)
Income taxes	(66)	8	14
Net income (loss)	$ 29	$ 40	$ 5

Operating Revenues

Southern Company's non-electric operating revenues from these other business activities decreased $11 million, or 15.7%, and $12 million, or 14.6%, in 2012 and 2011, respectively, as compared to the prior years. The decreases were 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

In 2012, the change in other operations and maintenance expenses for these other businesses was not material. Other operations and maintenance expenses for these other businesses decreased $9 million, or 8.6%, in 2011 as compared to the prior year. The decrease in 2011 was primarily the result of lower administrative and general expenses.

MC Asset Recovery Insurance Settlement

On June 14, 2012, Southern Company received an insurance recovery related to the litigation settlement with MC Asset Recovery, LLC, which resulted in income of $19 million. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

Interest Income

Interest income for these other businesses increased $16 million in 2012 as compared to the prior year primarily due to the conclusion of certain federal income tax audits. In 2011, the change in interest income for these other businesses was not material.

Leveraged Lease Income (Losses)

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. The change in leveraged lease income (losses) in 2012 compared to 2011 was not material. Leveraged lease income (losses) increased $7 million, or 38.9%, in 2011 as compared to the prior year primarily as a result of changes in the average leveraged lease investment balance. See FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" herein for additional information.

Other Income (Expense), Net

Other income (expense), net for these other businesses increased $11 million in 2012 and $6 million in 2011 as compared to the prior years primarily as a result of decreases in the amount of charitable contributions made by the parent company.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $15 million, or 27.8%, in 2012 and $8 million, or 12.9%, in 2011 as compared to the prior years primarily due to lower interest rates on existing debt.

Income Taxes

Income taxes for these other businesses increased $8 million, or 10.8%, in 2012 as compared to the prior year primarily as a result of lower pre-tax losses. Income taxes for these other business increased $14 million, or 15.9%, in 2011 as compared to the prior year primarily as a result of lower pre-tax losses and a prior year state tax adjustment related to leveraged leases.

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 Federal Energy Regulatory Commission (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 successful completion of ongoing construction projects, including construction of generating facilities. Another major factor is the profitability of the competitive wholesale supply business. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities and other wholesale customers, energy conservation practiced 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 supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in economic conditions impact sales for the traditional operating companies and Southern Power, and the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

In 2012, the Southern Company system generating capacity increased 2,184 megawatts (MWs), net of retirements of 352 MWs, due to the completion of Plant McDonough-Atkinson Units 5 and 6, the completion of a biomass generating plant, the completion of Plant Cleveland County Units 1 through 4, and the acquisition of three solar photovoltaic facilities. In general, the Southern Company system has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of the Southern Company system's regulated retail markets, both of which are optimized by limited energy trading activities. See "Construction Program" herein for additional information.

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, 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. 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

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter 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 2012, the traditional operating companies had invested approximately $8.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $340 million, $300 million, and $500 million for 2012, 2011, and 2010, respectively. The Southern Company system expects that capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $3.6 billion from 2013 through 2015, with annual totals of approximately $1.0 billion, $1.5 billion, and $1.1 billion for 2013, 2014, and 2015, respectively.

The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, the Southern Company system does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Byproducts" herein 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, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – Georgia Power – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions at Georgia Power.

Southern Electric Generating Company (SEGCO) is jointly owned by Alabama Power and Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such costs cannot continue to be recovered through retail rates, they could have a material financial impact on Southern Company's financial statements. See Note 4 to the financial statements herein for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, 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 $7.6 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.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. The only area within the traditional operating companies' service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

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 National Ambient Air Quality Standards and, in January 2013, the EPA officially redesignated the Birmingham area as attainment under both the annual and 24-hour standards. Redesignation requests for nonattainment areas in Georgia are still pending with the EPA. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the traditional operating companies' service territories.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010 (SO_2 Rule). The EPA plans to issue area designations under this new standard in June 2013, and areas within the Southern Company system's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. In April 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by Alabama Power, including units co-owned by Mississippi Power. Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves Alabama Power's appeal in its favor, the EPA's rescission will continue to affect Alabama Power's operations.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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 (BART) to certain sources 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 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final 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, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 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.

On January 31, 2013, the EPA published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup. Georgia Power is evaluating the impact of this final rule and other environmental regulations on the possible conversion of Plant Mitchell Unit 3 from coal to biomass.

On February 12, 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 proposes a determination that the SSM provisions in the SIPs for 36 states (including Alabama, Florida, Georgia, Mississippi, and North Carolina) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, the IB MACT rule, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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 is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2012, Georgia Power had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units.

On February 21, 2013, the State of Georgia released proposed revisions for both the Multi-Pollutant Rule and the SO_2 Rule revising the compliance dates for those units yet to be controlled to make them consistent with the April 2015 compliance date for the MATS rule. According to the State of Georgia, the proposed revisions would also allow the units at Plant Yates to use natural gas as the primary fuel as an alternative to installing controls under the Multi-Pollutant Rule. The revisions to the Multi-Pollutant Rule and the SO_2 Rule are expected to be finalized in April 2013. The ultimate outcome of these matters cannot be determined at this time.

Water Quality

In April 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the traditional operating companies' and Southern Power's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the facilities of Southern Company's subsidiaries may be subject to 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the facilities of Southern Company's subsidiaries, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The traditional operating companies currently operate 22 electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the traditional operating companies also sell a portion of their coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the states in the Southern Company system's service territory each have their own regulatory parameters. Each traditional operating company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion byproducts, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion byproducts: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion byproducts from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion byproducts.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the traditional operating companies could incur additional material asset retirement obligations with respect to closing existing storage facilities. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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 have recognized in their respective 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

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. In addition, over the past several years, the U.S. Congress has 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.

On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Southern Company system's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of a significant number of coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide 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 2011 greenhouse gas emissions were approximately 125 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Southern Company system's 2012 greenhouse gas emissions on the same basis is approximately 98 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

Alabama Power

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. 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%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, Alabama Power is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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 certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, 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, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, Alabama Power had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 MWs of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Rate CNP Environmental also 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 to recover environmental costs in 2011 or 2012. On November 26, 2012, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2013 the factors associated with Alabama Power's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, Alabama Power had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. 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.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the Nuclear Regulatory Commission (NRC) will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. See "Other Matters" herein for information regarding the NRC's guidance issued as a result of the earthquake and tsunami that struck Japan in 2011. In addition, the accounting order authorizes Alabama Power to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets.

Natural Disaster Reserve

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 Natural Disaster Reserve (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. 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.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider and NCCR tariff adjustments described in Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Nuclear Construction."

Under the 2010 ARP, Georgia Power's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011 or 2012. Georgia Power is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" 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 guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; the State of Georgia's Multi-Pollutant Rule; 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; and the 2010 ARP.

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

On January 31, 2013, Georgia Power filed its triennial IRP (2013 IRP). The filing included 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.

Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. 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 retired by April 16, 2015, the compliance date of the MATS rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included Georgia Power's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, Georgia Power plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. Georgia Power also reclassified the CWIP balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. Georgia Power has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on Southern Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2012, the balance in the regulatory asset related to storm damage was $38 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. The traditional operating companies have experienced lower pricing for natural gas resulting in an increase in natural gas generation and a decrease in coal generation, which is currently more costly. The lower cost of natural gas has resulted in total over recovered fuel costs in the balance sheets of Georgia Power, Gulf Power, and Mississippi Power of approximately $303 million at December 31, 2012. Total under recovered fuel costs were approximately $4 million in the balance sheet of Alabama Power at December 31, 2012. At December 31, 2011, total under recovered fuel costs in the balance sheets of Alabama Power and Georgia Power were approximately $169 million, and total over recovered fuel costs in the balance sheets of Gulf Power and Mississippi Power were approximately $52 million.

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 annual cash flow. The traditional operating companies continuously monitor the under or over recovered fuel cost balances.

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

Income Tax Matters

Bonus Depreciation

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Company through 2013.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation will have a positive impact on the future cash flows of Southern Company through 2014.

Due to the significant amount of estimated bonus depreciation for 2013, a portion of Southern Company's tax credit utilization will be deferred. Consequently, Southern Company's positive cash flow benefit is estimated to be between $275 million and $310 million in 2013.

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, including the ongoing construction of solar units at Southern Power, Plant Vogtle Units 3 and 4 at Georgia Power, and the Kemper IGCC at Mississippi Power, 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 approvals 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 $5.5 billion, $5.8 billion, and $5.2 billion for 2013, 2014, and 2015, respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest in two units, each with approximately 1,100 MWs) and the construction of the Kemper IGCC (for a total of 582 MWs). See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of 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.

Investments in Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Due to the poor performance of the generation assets and the uncertainties surrounding the receipt of future rent payments and its ability to successfully restructure the project, Southern Company placed the lease on nonaccrual status whereby, effective July 2012, income associated with this investment is not recognized in the financial statements. The lessee was unable to pay its December 2012 semiannual rent payment in full. To avoid a default on the lease and the project's nonrecourse debt, the due date for the December 2012 rent payment and the associated debt payment was extended to March 6, 2013 while restructuring negotiations continued between the parties to the transaction. The aim of the negotiations is to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made by Southern Company to improve the operation of the generation assets. Such operational improvements are projected to provide sufficient cash flows for Southern Company to realize the full amount of its investment in the lease receivable. The parties to the lease have reached general agreement as to the restructuring and Southern Company believes that it is likely that it will be able to complete the restructuring prior to the end of the first quarter 2013. If the restructuring is successfully completed, Southern Company will be required to record a reduction in leveraged lease income of up to approximately $17 million at that time. However, if the restructuring is unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

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

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.

In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time; however, management does not currently anticipate that the associated compliance costs would have a material impact on Southern Company's financial statements.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

See "PSC Matters – Alabama Power – Compliance and Pension Cost Accounting Order" herein for additional information on Alabama Power's PSC approved accounting order, which allows the deferral of certain compliance-related operations and maintenance expenditures related to compliance with the NRC guidance.

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 95% of Southern Company's total operating revenues for 2012, 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. 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, nuclear decommissioning, 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 and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject them 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 statements.

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 developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

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 2013	Increase/ (Decrease) in Projected Obligation for Pension Plan at December 31, 2012	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2012
		(in millions)	
25 basis point change in discount rate	$32/$(30)	$346/$(327)	$72/$(68)
25 basis point change in salaries	$17/$(16)	$93/$(89)	$-/$-
25 basis point change in long-term return on plan assets	$21/$(21)	N/A	N/A

N/A – Not applicable

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2012. Southern 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 Southern Company system's cash needs. For the three-year period from 2013 through 2015, Southern 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, to add environmental equipment for existing generating 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 through debt and equity issuances. 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, 2012 as compared to December 31, 2011. In December 2012, certain of the traditional operating companies and other subsidiaries contributed $445 million to the qualified pension plan.

Net cash provided from operating activities in 2012 totaled $4.9 billion, a decrease of $1.0 billion from the corresponding period in 2011. Significant changes in operating cash flow for 2012 as compared to the corresponding period in 2011 include an increase in fossil fuel stock and contributions to the qualified pension plan. Net cash provided from operating activities in 2011 totaled $5.9 billion, an increase of $1.9 billion from the corresponding period in 2010. Significant changes in operating cash flow for 2011 as compared to the corresponding period in 2010 include an increase in net income, a contribution to the qualified pension plan in 2010, and a decrease in taxes paid due to bonus depreciation.

Net cash used for investing activities in 2012, 2011, and 2010 totaled $5.2 billion, $4.2 billion, and $4.3 billion, respectively. The cash used for investing activities for each of these years was primarily for property additions to utility plant.

Net cash used for financing activities totaled $417 million in 2012 due to redemptions of long-term debt, the repurchase of common stock, and payments of common stock dividends, partially offset by issuances of long-term debt. Net cash used for financing activities totaled $852 million in 2011 due to a reduction of short-term debt outstanding and redemptions of long-term debt. Net cash provided from financing activities totaled $22 million in 2010 primarily due to long-term debt issuances offset mostly by long-term debt redemptions. 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 2012 include an increase of $3.4 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. Other significant changes include a decrease in cash of $687 million primarily due to a decrease in temporary cash investments, an increase in deferred income taxes of $1.1 billion due to bonus depreciation, and $719 million of additional equity.

At the end of 2012, the closing price of Southern Company's common stock was $42.81 per share, compared with a book value of $21.09 per share. The market-to-book value ratio was 203% at the end of 2012, compared with 228% at year-end 2011.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow 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 2013, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described herein, the traditional operating companies and Southern Power plan 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, security issuances, term loans, short-term borrowings, 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.

In 2010, Georgia Power reached an agreement with the U.S. Department of Energy (DOE) to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or Georgia Power determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, Georgia Power expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for more information on Plant Vogtle Units 3 and 4.

In addition, Mississippi Power received DOE Clean Coal Power Initiative Round 2 (CCPI2) grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. On January 29, 2013, Mississippi Power withdrew its application for federal loan guarantees related to 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 Securities and Exchange Commission (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.

Southern 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 of the Southern Company system. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

At December 31, 2012, Southern Company and its subsidiaries had approximately $628 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Company	Expires[(a)] 2013	2014	2016	Total	Unused	Executable Term Loans One Year	Two Years	Due Within One Year Term Out	No Term Out
		(in millions)		*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ —	$ —	$ 1,000	$ 1,000	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	158	350	800	1,308	1,308	56	—	56	102
Georgia Power	—	250	1,500	1,750	1,740	—	—	—	—
Gulf Power	80	195	—	275	275	45	—	45	35
Mississippi Power	135	165	—	300	300	25	40	65	70
Southern Power	—	—	500	500	500	—	—	—	—
Other	50	—	—	50	50	25	—	25	25
Total	$ 423	$ 960	$ 3,800	$ 5,183	$ 5,173	$ 151	$ 40	$ 191	$ 232

(a) No credit arrangements expire in 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

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, 2012 was approximately $1.8 billion.

The traditional operating companies 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 each of the traditional operating companies.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[(a)] Amount Outstanding	Weighted Average Interest Rate	Short-term Debt During the Period [(b)] Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
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%**	
December 31, 2011:					
Commercial paper	$ 654	0.3 %	$ 697	0.3 %	$ 1,586
Short-term bank debt	200	1.2 %	14	1.2 %	200
Total	$ 854	0.5 %	$ 711	0.3 %	
December 31, 2010:					
Commercial paper	$ 1,295	0.3 %	$ 690	0.3 %	$ 1,305

(a) Excludes notes payable related to other energy service contracts of $5 million, $6 million, and $2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

Management believes that the need for working capital can be adequately met by utilizing commercial paper programs, lines of credit, and cash.

Financing Activities

During 2012, Southern Company issued 12.1 million shares of common stock for approximately $397 million through the employee and director stock plans. Since mid-2011, Southern Company has issued additional equity only through its employee and director stock plans. In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. Under this program, approximately 9 million shares have been repurchased through December 31, 2012 at a total cost of $430 million. Pursuant to Board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

In addition, Southern Company is not currently issuing shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by the independent plan administrators.

The following table outlines the long-term debt financing activities for Southern Company, the traditional operating companies, and Southern Power for the year ended December 31, 2012:

Company	Senior Note Issuances	Senior Note Redemptions and Maturities	Revenue Bond Issuances	Revenue Bond Redemptions and Maturities	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities
			(in millions)			
Southern Company	$ —	$ 500	$ —	$ —	$ —	$ —
Alabama Power	1,000	950	—	1	—	—
Georgia Power	2,300	850	284	284	—	250
Gulf Power	100	91	13	13	—	—
Mississippi Power	600	90	—	—	101	115
Southern Power	—	—	—	—	6	2
Total	$ 4,000	$ 2,481	$ 297	$ 298	$ 107	$ 367

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 January 2012, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

The table above does not reflect Mississippi Power's receipt on March 6, 2012 of a $150 million interest-bearing refundable deposit from South Mississippi Electric Power Association (SMEPA) to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Rating Services, a division of The McGraw-Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Service, Inc. (Moody's) or ceases to be rated by either of these rating agencies.

Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above include $51 million related to an agreement entered into by the Mississippi Business Finance Corporation in August 2012 for the issuance of up to $85 million of taxable revenue bonds for the benefit of Mississippi Power. During 2012, the Mississippi Business Finance Corporation issued $51 million of taxable revenue bonds under the agreement, the proceeds of which were used by Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility relating to the Kemper IGCC. Any future issuances of up to $34 million under the agreement will be used for the same purposes.

In addition, Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above includes a term loan borrowing of $50 million. In November 2012, Mississippi Power entered into a one-year $100 million aggregate principal amount floating rate term loan agreement that bears interest based on one-month London Interbank Offered Rate. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

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.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, Mississippi Power began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4.

In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. Accordingly, Plant Daniel Units 3 and 4 were reflected in Southern Company's financial statements at approximately $431 million.

In connection with the purchase of Plant Daniel Units 3 and 4, Mississippi Power filed a request in July 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized Mississippi Power to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for 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 rates over the remaining life of Plant Daniel Units 3 and 4. In November 2011, Mississippi Power filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The ultimate outcome of this matter cannot be determined at this time.

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, emissions allowances, energy price risk management, and construction of new generation.

The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	645
Below BBB- and/or Baa3	2,574

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

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, 2012 have a notional amount of $350 million and are related to fixed and floating rate obligations over the next several years. The weighted average interest rate on $3.2 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2013 was 0.73%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $32 million at January 1, 2013. 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 sales 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, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (231)**	$ (196)
Contracts realized or settled	**206**	179
Current period changes[(a)]	**(60)**	(214)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (85)**	$ (231)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Natural gas swaps	**$ 128**	$ (20)
Natural gas options	**19**	(15)
Other energy-related derivatives	**(1)**	—
Total changes	**$ 146**	$ (35)

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2012	2011
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	**171**	123
Commodity – Natural gas options	**105**	66
Total hedge volume	**276**	189

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.39 per mmBtu as of December 31, 2012 and $1.51 per mmBtu as of December 31, 2011. 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, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	**2012**	2011
	(in millions)	
Regulatory hedges	**$ (86)**	$ (221)
Cash flow hedges	**—**	(1)
Not designated	**1**	(9)
Total fair value	**$ (85)**	$ (231)

Energy-related derivative contracts which are designated as regulatory hedges relate 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 they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in other comprehensive income 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.

Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2012, 2011, and 2010 for energy-related derivative contracts that are not hedges were $9 million, $(6) million, and $(2) million, respectively.

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, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ —	$ —	$ —	$ —
Level 2	(85)	(64)	(23)	2
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (85)	$ (64)	$ (23)	$ 2

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. See FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" herein for additional information.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to be $5.5 billion for 2013, $5.8 billion for 2014, and $5.2 billion for 2015. Included in this amount are expenditures related to the construction of the Kemper IGCC of $513 million and $218 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the Kemper IGCC of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest). Capital expenditures to comply with existing environmental statutes and regulations included in these estimated amounts are $1.0 billion, $1.5 billion, and $1.1 billion for 2013, 2014, and 2015, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, as well as capital expenditures and compliance costs associated with the MATS rule.

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 the expected environmental compliance program; 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 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 – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

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

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
			(in millions)			
Long-term debt[a] —						
Principal	$ 2,312	$ 2,866	$ 2,495	$ 13,804	$ —	$ 21,477
Interest	821	1,491	1,318	10,214	—	13,844
Preferred and preference stock dividends[b]	65	130	130	—	—	325
Financial derivative obligations[c]	75	35	1	—	—	111
Operating leases	113	148	77	84	—	422
Capital leases	23	21	15	21	—	80
Unrecognized tax benefits[d]	5	—	—	—	65	70
Purchase commitments —						
Capital[e]	4,987	10,013	—	—	—	15,000
Fuel[f]	4,518	6,070	2,638	3,280	—	16,506
Purchased power[g]	246	617	650	2,903	—	4,416
Other[h]	184	516	271	1,034	—	2,005
Trusts —						
Nuclear decommissioning[i]	2	4	4	31	—	41
Pension and other postretirement benefit plans[j]	102	201	—	—	—	303
Total	$ 13,453	$ 22,112	$ 7,599	$ 31,371	$ 65	$ 74,600

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan 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, 2013, 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) For additional information, see Notes 1 and 11 to the financial statements.

(d) The timing related to the realization of $65 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. 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, 2012, 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) 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, 2012.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts include 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) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for Georgia Power.

(j) 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 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, dividend payout ratios, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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 the 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 recent recession, population and business growth (and declines), the effects of energy conservation measures, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, including the development and construction of facilities with designs that have not been finalized or previously constructed, 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;
- investment performance of Southern Company's employee 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;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the certificate of public convenience and necessity for the Kemper IGCC;
- 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 terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;

- the impacts of any potential U.S. credit rating downgrade or other 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 availability or benefits of proposed 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, 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, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 14,187**	$ 15,071	$ 14,791
Wholesale revenues	**1,675**	1,905	1,994
Other electric revenues	**616**	611	589
Other revenues	**59**	70	82
Total operating revenues	**16,537**	17,657	17,456
Operating Expenses:			
Fuel	**5,057**	6,262	6,699
Purchased power	**544**	608	563
Other operations and maintenance	**3,791**	3,938	4,010
MC Asset Recovery insurance settlement	**(19)**	—	—
Depreciation and amortization	**1,787**	1,717	1,513
Taxes other than income taxes	**914**	901	869
Total operating expenses	**12,074**	13,426	13,654
Operating Income	**4,463**	4,231	3,802
Other Income and (Expense):			
Allowance for equity funds used during construction	**143**	153	194
Interest income	**40**	21	24
Interest expense, net of amounts capitalized	**(859)**	(857)	(895)
Other income (expense), net	**(38)**	(61)	(59)
Total other income and (expense)	**(714)**	(744)	(736)
Earnings Before Income Taxes	**3,749**	3,487	3,066
Income taxes	**1,334**	1,219	1,026
Consolidated Net Income	**2,415**	2,268	2,040
Dividends on Preferred and Preference Stock of Subsidiaries	**65**	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 2,350**	$ 2,203	$ 1,975
Common Stock Data:			
Earnings per share (EPS)—			
Basic EPS	**$ 2.70**	$ 2.57	$ 2.37
Diluted EPS	**2.67**	2.55	2.36
Average number of shares of common stock outstanding — (in millions)			
Basic	**871**	857	832
Diluted	**879**	864	837
Cash dividends paid per share of common stock	**$ 1.9425**	$ 1.8725	$ 1.8025

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Consolidated Net Income	**$ 2,415**	$ 2,268	$ 2,040
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(7), $(10), and $-, respectively	**(12)**	(18)	(1)
Reclassification adjustment for amounts included in net income, net of tax of $7, $6, and $9, respectively	**11**	9	15
Marketable securities:			
Change in fair value, net of tax of $-, $(2), and $(2), respectively	**—**	(4)	(3)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(2), $(1), and $1, respectively	**(3)**	(2)	6
Reclassification adjustment for amounts included in net income, net of tax of $(4), $(14), and $1, respectively	**(8)**	(26)	1
Total other comprehensive income (loss)	**(12)**	(41)	18
Dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Consolidated Comprehensive Income	**$ 2,338**	$ 2,162	$ 1,993

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Activities:			
Consolidated net income	$ 2,415	$ 2,268	$ 2,040
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,145	2,048	1,831
Deferred income taxes	1,096	1,155	1,038
Allowance for equity funds used during construction	(143)	(153)	(194)
Pension, postretirement, and other employee benefits	(398)	(45)	(614)
Stock based compensation expense	55	42	33
Generation construction screening costs	—	—	(51)
Retail fuel cost-recovery - long-term	123	—	—
Other, net	56	15	(33)
Changes in certain current assets and liabilities —			
-Receivables	234	362	80
-Fossil fuel stock	(452)	(62)	135
-Materials and supplies	(97)	(60)	(30)
-Other current assets	(37)	(17)	(17)
-Accounts payable	(89)	(5)	4
-Accrued taxes	(71)	330	(308)
-Accrued compensation	(28)	10	180
-Retail fuel cost over recovery - short-term	129	(3)	(178)
-Other current liabilities	(40)	18	75
Net cash provided from operating activities	4,898	5,903	3,991
Investing Activities:			
Property additions	(4,809)	(4,525)	(4,086)
Investment in restricted cash	(280)	1	(50)
Distribution of restricted cash	284	63	25
Nuclear decommissioning trust fund purchases	(1,046)	(2,195)	(2,009)
Nuclear decommissioning trust fund sales	1,043	2,190	2,004
Cost of removal, net of salvage	(149)	(93)	(125)
Change in construction payables, net	(84)	198	29
Other investing activities	(127)	178	(44)
Net cash used for investing activities	(5,168)	(4,183)	(4,256)
Financing Activities:			
Increase (decrease) in notes payable, net	(30)	(438)	659
Proceeds —			
Long-term debt issuances	4,404	3,719	3,151
Interest-bearing refundable deposit related to asset sale	150	—	—
Common stock issuances	397	723	772
Redemptions and repurchases —			
Long-term debt	(3,169)	(3,170)	(2,966)
Common stock repurchased	(430)	—	—
Payment of common stock dividends	(1,693)	(1,601)	(1,496)
Payment of dividends on preferred and preference stock of subsidiaries	(65)	(65)	(65)
Other financing activities	19	(20)	(33)
Net cash provided from (used for) financing activities	(417)	(852)	22
Net Change in Cash and Cash Equivalents	(687)	868	(243)
Cash and Cash Equivalents at Beginning of Year	1,315	447	690
Cash and Cash Equivalents at End of Year	$ 628	$ 1,315	$ 447

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

Assets	2012	2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 628	$ 1,315
Restricted cash and cash equivalents	7	8
Receivables —		
Customer accounts receivable	961	1,074
Unbilled revenues	441	376
Under recovered regulatory clause revenues	29	143
Other accounts and notes receivable	235	282
Accumulated provision for uncollectible accounts	(17)	(26)
Fossil fuel stock, at average cost	1,819	1,367
Materials and supplies, at average cost	1,000	903
Vacation pay	165	160
Prepaid expenses	657	385
Other regulatory assets, current	163	239
Other current assets	74	46
Total current assets	6,162	6,272
Property, Plant, and Equipment:		
In service	63,251	59,744
Less accumulated depreciation	21,964	21,154
Plant in service, net of depreciation	41,287	38,590
Other utility plant, net	263	55
Nuclear fuel, at amortized cost	851	774
Construction work in progress	5,989	5,591
Total property, plant, and equipment	48,390	45,010
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,303	1,207
Leveraged leases	670	649
Miscellaneous property and investments	216	262
Total other property and investments	2,189	2,118
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,385	1,365
Unamortized debt issuance expense	133	156
Unamortized loss on reacquired debt	309	285
Other regulatory assets, deferred	4,032	3,579
Other deferred charges and assets	549	482
Total deferred charges and other assets	6,408	5,867
Total Assets	$ 63,149	$ 59,267

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

Liabilities and Stockholders' Equity	2012	2011
	(in millions)	
Current Liabilities:		
Securities due within one year	$ 2,335	$ 1,717
Interest-bearing refundable deposit related to asset sale	150	—
Notes payable	825	859
Accounts payable	1,387	1,553
Customer deposits	370	347
Accrued taxes —		
Accrued income taxes	7	13
Unrecognized tax benefits	2	22
Other accrued taxes	391	425
Accrued interest	237	226
Accrued vacation pay	212	205
Accrued compensation	433	450
Liabilities from risk management activities	75	209
Other regulatory liabilities, current	107	125
Other current liabilities	483	426
Total current liabilities	7,014	6,577
Long-Term Debt (See accompanying statements)	19,274	18,647
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	9,938	8,809
Deferred credits related to income taxes	211	224
Accumulated deferred investment tax credits	894	611
Employee benefit obligations	2,540	2,442
Asset retirement obligations	1,748	1,321
Other cost of removal obligations	1,194	1,165
Other regulatory liabilities, deferred	289	297
Other deferred credits and liabilities	668	514
Total deferred credits and other liabilities	17,482	15,383
Total Liabilities	43,770	40,607
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	375	375
Total Stockholders' Equity (See accompanying statements)	19,004	18,285
Total Liabilities and Stockholders' Equity	$ 63,149	$ 59,267
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

		2012	2011	2012	2011
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Maturity					
Variable rate (3.41% at 1/1/13) due 2042		**$ 206**	$ 206		
Total long-term debt payable to affiliated trusts		**206**	206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2012	4.85% to 5.30%	**—**	1,203		
2013	1.30% to 6.00%	**1,436**	1,436		
2014	4.15% to 4.90%	**434**	437		
2015	0.55% to 5.25%	**2,375**	1,175		
2016	1.95% to 5.30%	**1,360**	1,210		
2017	5.50% to 5.90%	**1,095**	1,095		
2018 through 2051	2.25% to 8.20%	**10,073**	8,702		
Variable rates (0.60% to 0.95% at 1/1/12) due 2012		**—**	490		
Variable rates (0.58% to 1.21% at 1/1/13) due 2013		**876**	650		
Total long-term senior notes and debt		**17,649**	16,398		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019 through 2049	0.55% to 6.00%	**1,593**	1,590		
Variable rate (0.13% at 1/1/13) due 2015		**54**	54		
Variable rate (0.17% at 1/1/13) due 2016		**4**	4		
Variable rate (0.13% to 0.17% at 1/1/13) due 2017		**36**	36		
Variable rates (0.08% to 0.24% at 1/1/13) due 2018 to 2052		**1,664**	1,667		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
Total other long-term debt		**3,621**	3,621		
Capitalized lease obligations		**80**	93		
Unamortized debt premium (related to plant acquisition)		**88**	78		
Unamortized debt discount		**(35)**	(32)		
Total long-term debt (annual interest requirement — $821 million)		**21,609**	20,364		
Less amount due within one year		**2,335**	1,717		
Long-term debt excluding amount due within one year		**19,274**	18,647	**49.9%**	50.0%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2012	2011
	(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	**1.0**	1.0
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,389**	4,328		
Authorized — 1.5 billion shares				
Issued — 2012: 878 million shares				
— 2011: 866 million shares				
Treasury — 2012: 10.0 million shares				
— 2011: 0.5 million shares				
Paid-in capital	**4,855**	4,410		
Treasury, at cost	**(450)**	(17)		
Retained earnings	**9,626**	8,968		
Accumulated other comprehensive income (loss)	**(123)**	(111)		
Total common stockholders' equity	**18,297**	17,578	**47.3**	47.1
Preferred and Preference Stock of Subsidiaries:				
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 — 5.63% to 6.50%	**343**	343		
— 14 million shares (non-cumulative)				
— $100 par or stated value — 6.00% to 6.50%	**319**	319		
— 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement — $45 million)	**707**	707	**1.8**	1.9
Total stockholders' equity	**19,004**	18,285		
Total Capitalization	**$ 38,653**	$ 37,307	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	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	Total
	(in thousands)		*(in millions)*						
Balance at December 31, 2009	820,152	(505)	$ 4,101	$ 2,995	$ (15)	$ 7,885	$ (88)	$ 707	$ 15,585
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,975	—	—	1,975
Other comprehensive income (loss)	—	—	—	—	—	—	18	—	18
Stock issued	23,662	—	118	654	—	—	—	—	772
Stock-based compensation	—	—	—	52	—	—	—	—	52
Cash dividends	—	—	—	—	—	(1,496)	—	—	(1,496)
Other	—	31	—	1	—	2	—	—	3
Balance at December 31, 2010	843,814	(474)	4,219	3,702	(15)	8,366	(70)	707	16,909
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,203	—	—	2,203
Other comprehensive income (loss)	—	—	—	—	—	—	(41)	—	(41)
Stock issued	21,850	—	109	616	—	—	—	—	725
Stock-based compensation	—	—	—	89	—	—	—	—	89
Cash dividends	—	—	—	—	—	(1,601)	—	—	(1,601)
Other	—	(65)	—	3	(2)	—	—	—	1
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	—	—	—	—	—	**(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**

The accompanying notes are an integral part of these 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 Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (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 (VIEs) where the Company has an equity investment, but is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow generally accepted accounting principles (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.

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:

		2012		2011	Note
		(in millions)			
Deferred income tax charges	$	**1,318**	$	1,293	(a)
Deferred income tax charges — Medicare subsidy		**72**		77	(j)
Asset retirement obligations-asset		**141**		117	(a,h)
Asset retirement obligations-liability		**(71)**		(42)	(a,h)
Other cost of removal obligations		**(1,225)**		(1,196)	(a)
Deferred income tax credits		**(212)**		(225)	(a)
State income tax credits		**(36)**		(62)	(k)
Loss on reacquired debt		**309**		285	(b)
Vacation pay		**165**		160	(c,h)
Under recovered regulatory clause revenues		**38**		50	(d)
Over recovered regulatory clause revenues		**(18)**		(28)	(d)
Building leases		**40**		43	(f)
Generating plant outage costs		**30**		38	(l)
Under recovered storm damage costs		**38**		43	(d)
Property damage reserves		**(193)**		(206)	(g)
Cancelled construction projects		**65**		12	(m)
Power purchase agreement charges		**138**		95	(h,n)
Fuel hedging-asset		**118**		249	(d)
Fuel hedging-liability		**(24)**		(13)	(d)
Other regulatory assets		**204**		183	(d)
Environmental remediation-asset		**74**		71	(g,h)
Environmental remediation-liability		**(8)**		(8)	(g)
Other regulatory liabilities		**(14)**		(30)	(d,i)
Retiree benefit plans		**3,373**		2,959	(e,h)
Total regulatory assets (liabilities), net	$	**4,322**	$	3,865	

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. At December 31, 2012, other cost of removal obligations included $31 million that will be amortized during 2013 in accordance with an Alternate Rate Plan for Georgia Power for the years 2011 through 2013 (2010 ARP). See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

(b) 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 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 appropriate state PSCs over periods generally not exceeding 10 years.

(e) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.

(f) Recovered over the remaining lives of the buildings through 2026.

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

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

(i) Recovered and amortized as approved or accepted by the appropriate state PSC over the life of the contract.

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

(k) Additional tax benefits resulting from the Georgia state income tax credit settlement that are being amortized over a 21-month period that began in April 2012, in accordance with a Georgia PSC order.

(l) Recovered over the respective operating cycles, which range from 18 months to 10 years. See "Property, Plant, and Equipment" herein for additional information.

(m) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and deferred in accordance with the 2010 ARP. Amortization is expected to begin January 1, 2014, subject to approval by the Georgia PSC.

(n) Recovered over the life of the power purchase agreement (PPA) for periods up to 14 years.

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 other comprehensive income (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 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 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. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

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 investment tax credits (ITCs) for the traditional operating companies are amortized over the 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 $23 million in 2012, $19 million in 2011, and $23 million in 2010. At December 31, 2012, 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.

Under the American Recovery and Reinvestment Act of 2009, certain projects at certain Southern Company subsidiaries are eligible for ITCs or cash grants. These subsidiaries have 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 $2.6 million and $0.9 million in 2012 and 2011, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The subsidiaries have elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period. These basis differences will reverse and be recorded to income tax expense over the useful life of the asset once placed in service.

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:

	2012	2011
	(in millions)	
Generation	$ 33,444	$ 31,751
Transmission	8,747	8,240
Distribution	15,958	15,458
General	4,208	3,413
Plant acquisition adjustment	124	124
Utility plant in service	62,481	58,986
Information technology equipment and software	230	220
Communications equipment	430	428
Other	110	110
Other plant in service	770	758
Total plant in service	$ 63,251	$ 59,744

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 expense 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 and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

The amount of non-cash property additions recognized for the years ended December 31, 2012, 2011, and 2010 was $524 million, $929 million, and $427 million, respectively. These amounts are comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year.

Included in the non-cash property additions for the year ended December 31, 2011 was $346 million for the fair value of the debt assumed for Mississippi Power's purchase of the combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4). In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. The fair value of the debt was determined using a discounted cash flow model based on Mississippi Power's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 are reflected in Southern Company's financial statements at approximately $431 million.

Southern Power acquires generation assets as part of its overall growth strategy. Southern Power accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. 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.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2012, 3.2% in 2011, and 3.3% in 2010. 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 $21.5 billion and $20.7 billion at December 31, 2012 and 2011, 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.

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 the 2010 ARP, Georgia Power is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. 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 $479 million and $456 million at December 31, 2012 and 2011, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations 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. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information related to Georgia Power's cost of removal regulatory liability.

The liability for asset retirement obligations 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, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, co-generation 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 range of time over which the applicable company may settle these obligations is unknown and cannot be reasonably estimated. 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 asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in millions)	
Balance at beginning of year	**$ 1,344**	$ 1,266
Liabilities incurred	**45**	1
Liabilities settled	**(16)**	(13)
Accretion	**112**	82
Cash flow revisions	**272**	8
Balance at end of year	**$ 1,757**	$ 1,344

Nuclear Decommissioning

The Nuclear Regulatory Commission (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 Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While Southern Company is 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 asset retirement obligations 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 so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2012 and 2011, approximately $91 million and $39 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 $93 million and $42 million at December 31, 2012 and 2011, 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, 2012, investment securities in the Funds totaled $1.3 billion consisting of equity securities of $718 million, debt securities of $564 million, and $20 million of other securities. At December 31, 2011, investment securities in the Funds totaled $1.2 billion consisting of equity securities of $626 million, debt securities of $543 million, and $36 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.0 billion, $2.2 billion, and $2.0 billion in 2012, 2011, and 2010, respectively, all of which were reinvested. 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. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $29 million, of which $41 million related to realized gains and $60 million related to unrealized losses related to securities held in the Funds at December 31, 2011. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $139 million, of which $6 million related to securities held in the Funds at December 31, 2010. 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 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, 2012, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
		(in millions)	
External trust funds	$ 604	$ 435	$ 256
Internal reserves	22	—	—
Total	$ 626	$ 435	$ 256

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2008 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	2065	2068	2072
		(in millions)	
Site study costs:			
Radiated structures	$ 1,060	$ 680	$ 568
Non-radiated structures	72	51	76
Total site study costs	$ 1,132	$ 731	$ 644

The decommissioning periods and site study costs for Plant Vogtle Units 1 and 2 reflect the extended operating license approved by the NRC in 2009. 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, 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 2009. Effective for the years 2011 through 2013, the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. 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 allowance for funds used during construction (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 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 8.2%, 9.1%, and 12.5% of net income for 2012, 2011, and 2010, respectively.

Cash payments for interest totaled $803 million, $832 million, and $789 million in 2012, 2011, and 2010, respectively, net of amounts capitalized of $83 million, $78 million, and $86 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 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 $28 million in 2012 and $29 million in 2011. Alabama Power, Gulf Power, and Mississippi Power also have the authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2012, there were no such additional accruals. In 2011, such additional accruals totaled $31 million, all at Alabama Power. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" for additional information regarding Alabama Power's natural disaster reserve.

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.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Due to the poor performance of the generation assets and the uncertainties surrounding the receipt of future rent payments and its ability to successfully restructure the project, Southern Company placed the lease on nonaccrual status whereby, effective July 2012, income associated with this investment is not recognized in the financial statements. The lessee was unable to pay its December 2012 semiannual rent payment in full. To avoid a default on the lease and the project's nonrecourse debt, the due date for the December 2012 rent payment and the associated debt payment was extended to March 6, 2013 while restructuring negotiations continued between the parties to the transaction. The aim of the negotiations is to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made by Southern Company to improve the operation of the generation assets. Such operational improvements are projected to provide sufficient cash flows for Southern Company to realize the full amount of its investment in the lease receivable. The parties to the lease have reached general agreement as to the restructuring and Southern Company believes that it is likely that it will be able to complete the restructuring prior to the end of the first quarter 2013. If the restructuring is successfully completed, Southern Company will be required to record a reduction in leveraged lease income of up to approximately $17 million at that time. However, if the restructuring is unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Southern Company's net investment in domestic and international leveraged leases consists of the following at December 31:

	2012	2011
	(in millions)	
Net rentals receivable	**$ 1,214**	$ 1,216
Unearned income	**(544)**	(567)
Investment in leveraged leases	**670**	649
Deferred taxes from leveraged leases	**(278)**	(277)
Net investment in leveraged leases	**$ 392**	$ 372

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

	2012	2011	2010
		(in millions)	
Pretax leveraged lease income	**$ 21**	$ 25	$ 18
Income tax expense	**(8)**	(9)	(8)
Net leveraged lease income	**$ 13**	$ 16	$ 10

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 Environmental Protection Agency (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. 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. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel hedging programs. This results 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 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.

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, 2012, 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, 2011	$ (44)	$ 3	$ (70)	$ (111)
Current period change	(1)	—	(11)	(12)
Balance at December 31, 2012	**$ (45)**	**$ 3**	**$ (81)**	**$ (123)**

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 2012, certain of the traditional operating companies and other subsidiaries contributed $445 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. 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, 2013, other postretirement trust contributions are expected to total approximately $28 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	**4.26%**	4.98%	5.52%
Other postretirement benefit plans	**4.05**	4.88	5.40
Annual salary increase	**3.59**	3.84	3.84
Long-term return on plan assets:			
Pension plans	**8.20**	8.45	8.45
Other postretirement benefit plans	**7.29**	7.39	7.40

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate Is Reached**
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 126	$ (106)
Service and interest costs	7	(6)

Pension Plans

The total accumulated benefit obligation for the pension plans was $8.5 billion at December 31, 2012 and $7.4 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 8,079	$ 7,223
Service cost	198	184
Interest cost	393	389
Benefits paid	(336)	(324)
Actuarial loss	968	607
Balance at end of year	9,302	8,079
Change in plan assets		
Fair value of plan assets at beginning of year	6,800	6,834
Actual return (loss) on plan assets	1,010	256
Employer contributions	479	34
Benefits paid	(336)	(324)
Fair value of plan assets at end of year	7,953	6,800
Accrued liability	$ (1,349)	$ (1,279)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $8.7 billion and $582 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	$ 3,013	$ 2,614
Other current liabilities	(37)	(34)
Employee benefit obligations	(1,312)	(1,245)
Accumulated OCI	125	109

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2012 and 2011 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 2013.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2012:		
Accumulated OCI	**$ 7**	**$ 118**
Regulatory assets	**100**	**2,913**
Total	**$ 107**	**$ 3,031**
Balance at December 31, 2011:		
Accumulated OCI	$ 7	$ 102
Regulatory assets	128	2,486
Total	$ 135	$ 2,588
Estimated amortization in net periodic pension cost in 2013:		
Accumulated OCI	$ 1	$ 8
Regulatory assets	26	192
Total	$ 27	$ 200

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, 2012 and 2011 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2010	$ 68	$ 1,749
Net (gain) loss	43	915
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(31)
Amortization of net gain (loss)	(1)	(20)
Total reclassification adjustments	(2)	(51)
Total change	41	865
Balance at December 31, 2011	$ 109	$ 2,614
Net (gain) loss	**21**	**519**
Change in prior service costs	—	—
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(29)**
Amortization of net gain (loss)	**(4)**	**(91)**
Total reclassification adjustments	**(5)**	**(120)**
Total change	**16**	**399**
Balance at December 31, 2012	**$ 125**	**$ 3,013**

Components of net periodic pension cost were as follows:

	2012	2011	2010
		(in millions)	
Service cost	$ 198	$ 184	$ 172
Interest cost	393	389	391
Expected return on plan assets	(581)	(607)	(552)
Recognized net loss	95	21	10
Net amortization	30	32	33
Net periodic pension cost	$ 135	$ 19	$ 54

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, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$ 376
2014	397
2015	419
2016	440
2017	465
2018 to 2022	2,632

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,787	$ 1,752
Service cost	21	21
Interest cost	85	92
Benefits paid	(99)	(103)
Actuarial loss	71	29
Plan amendments	—	(12)
Retiree drug subsidy	7	8
Balance at end of year	1,872	1,787
Change in plan assets		
Fair value of plan assets at beginning of year	765	802
Actual return on plan assets	93	4
Employer contributions	55	54
Benefits paid	(92)	(95)
Fair value of plan assets at end of year	821	765
Accrued liability	$ (1,051)	$ (1,022)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	$ 360	$ 345
Other current liabilities	(3)	(4)
Employee benefit obligations	(1,048)	(1,018)
Accumulated OCI	7	6

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2012 and 2011 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 2013.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2012:			
Accumulated OCI	$ —	$ 7	$ —
Regulatory assets	**13**	**342**	**5**
Total	**$ 13**	**$ 349**	**$ 5**
Balance at December 31, 2011:			
Accumulated OCI	$ —	$ 6	$ —
Regulatory assets	17	314	14
Total	$ 17	$ 320	$ 14
Estimated amortization as net periodic postretirement benefit cost in 2013:			
Accumulated OCI	$ —	$ —	$ —
Regulatory assets	4	12	5
Total	$ 4	$ 12	$ 5

The components of OCI, along with the changes in the balance of regulatory assets, related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2010	$ 3	$ 292
Net (gain) loss	3	84
Change in prior service costs/transition obligation	—	(12)
Reclassification adjustments:		
Amortization of transition obligation	—	(10)
Amortization of prior service costs	—	(5)
Amortization of net gain (loss)	—	(4)
Total reclassification adjustments	—	(19)
Total change	3	53
Balance at December 31, 2011	$ 6	$ 345
Net (gain) loss	**1**	**35**
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	—	**(10)**
Amortization of prior service costs	—	**(4)**
Amortization of net gain (loss)	—	**(6)**
Total reclassification adjustments	—	**(20)**
Total change	**1**	**15**
Balance at December 31, 2012	**$ 7**	**$ 360**

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

	2012	2011	2010
		(in millions)	
Service cost	**$ 21**	$ 21	$ 25
Interest cost	**85**	92	100
Expected return on plan assets	**(60)**	(64)	(63)
Net amortization	**20**	20	20
Net postretirement cost	**$ 66**	$ 69	$ 82

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)	
2013	$ 110	$ (11)	$ 99
2014	116	(12)	104
2015	122	(13)	109
2016	127	(14)	113
2017	130	(16)	114
2018 to 2022	661	(88)	573

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, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	**2012**	2011
Pension plan assets:			
Domestic equity	26%	**28%**	29%
International equity	25	**24**	25
Fixed income	23	**27**	23
Special situations	3	**1**	—
Real estate investments	14	**13**	14
Private equity	9	**7**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	40%	**38%**	39%
International equity	21	**24**	18
Domestic fixed income	25	**28**	31
Global fixed income	4	**3**	4
Special situations	1	**—**	—
Real estate investments	6	**5**	5
Private equity	3	**2**	3
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, 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, 2012 and 2011. 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:

- **Investments in equity securities:** 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.
- **Investments in fixed income securities:** 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.
- **Investments in 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.
- **Investments in private equity and real estate:** 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, 2012 and 2011 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, 2012:	**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*	$ 1,163	$ 670	$ —	$ 1,833
International equity*	912	979	—	1,891
Fixed income:				
U.S. Treasury, government, and agency bonds	—	516	—	516
Mortgage- and asset-backed securities	—	127	—	127
Corporate bonds	—	876	3	879
Pooled funds	—	399	—	399
Cash equivalents and other	5	548	—	553
Real estate investments	258	—	841	1,099
Private equity	—	—	593	593
Total	$ 2,338	$ 4,115	$ 1,437	$ 7,890

* 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, 2011:	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*	$ 1,155	$ 533	$ —	$ 1,688
International equity*	1,187	340	—	1,527
Fixed income:				
U.S. Treasury, government, and agency bonds	—	433	—	433
Mortgage- and asset-backed securities	—	135	—	135
Corporate bonds	—	832	3	835
Pooled funds	—	380	—	380
Cash equivalents and other	1	139	—	140
Real estate investments	220	—	782	1,002
Private equity	—	—	582	582
Total	$ 2,563	$ 2,792	$ 1,367	$ 6,722

* 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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
	(in millions)			
Beginning balance	**$ 782**	**$ 582**	$ 674	$ 638
Actual return on investments:				
Related to investments held at year end	**56**	**1**	72	(12)
Related to investments sold during the year	**3**	**41**	20	47
Total return on investments	**59**	**42**	92	35
Purchases, sales, and settlements	—	**(31)**	16	(91)
Transfers into/out of Level 3	—	—	—	—
Ending balance	**$ 841**	**$ 593**	$ 782	$ 582

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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, 2012:	**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*	$ 140	$ 43	$ —	$ 183
International equity*	33	75	—	108
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	4	—	4
Corporate bonds	—	31	—	31
Pooled funds	—	42	—	42
Cash equivalents and other	—	44	—	44
Trust-owned life insurance	—	320	—	320
Real estate investments	10	—	30	40
Private equity	—	—	21	21
Total	$ 183	$ 583	$ 51	$ 817

* 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, 2011:	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*	$ 156	$ 38	$ —	$ 194
International equity*	45	39	—	84
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	5	—	5
Corporate bonds	—	32	—	32
Pooled funds	—	48	—	48
Cash equivalents and other	—	46	—	46
Trust-owned life insurance	—	291	—	291
Real estate investments	9	—	30	39
Private equity	—	—	23	23
Total	$ 210	$ 523	$ 53	$ 786

* 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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	**$ 30**	**$ 23**	$ 26	$ 23
Actual return on investments:				
Related to investments held at year end	—	—	3	—
Related to investments sold during the year	—	**1**	1	2
Total return on investments	—	**1**	4	2
Purchases, sales, and settlements	—	**(3)**	—	(2)
Transfers into/out of Level 3	—	—	—	—
Ending balance	**$ 30**	**$ 21**	$ 30	$ 23

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 2012, 2011, and 2010 were $82 million, $78 million, and $76 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 increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide (CO_2) and other emissions, coal combustion byproducts, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. 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 a nontaxable $25 million payment from its insurance provider on June 14, 2012. Additionally, legal fees related to this insurance settlement totaled approximately $6 million. As a result, the net reduction to expense presented as MC Asset Recovery insurance settlement in the statement of income was approximately $19 million.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether Southern Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter 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, 2012 was $19 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 large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). 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 on the Georgia Hazardous Sites Inventory and the CERCLA NPL 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 September 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. In November 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 November 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If 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. On February 1, 2013, the court granted Georgia Power's summary judgment motion ruling that Georgia Power has no liability in the private action. The plaintiffs may appeal the court'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 regulatory treatment, 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 $61 million as of December 31, 2012. 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 will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

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 U.S. Department of Energy (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. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, Alabama Power and Georgia Power have 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 substantially all 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 2008, Alabama Power and Georgia Power filed a second lawsuit 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. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 for any potential recoveries from the second lawsuit. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 has begun. The facility is expected to begin operation in sufficient time to maintain full-core discharge capability, with additional on-site dry storage to be added as needed. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Alabama Power

Retail Rate Adjustments

In July 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the natural disaster reserve (NDR) in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the April 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. 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%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, Alabama Power is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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 certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, 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, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, Alabama Power had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

Alabama Power's retail rates, approved by the Alabama PSC also allow for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates (Rate CNP Environmental). 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 to recover environmental costs in 2011 or 2012. On November 26, 2012, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2013 the factors associated with Alabama Power's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, Alabama Power had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. These costs would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Compliance and Pension Cost Accounting Order

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the NRC will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. In addition, the accounting order authorizes Alabama Power to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets.

Energy Cost Recovery

Alabama Power has established energy cost recovery rates under Alabama Power's energy cost recovery rate (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 kilowatt hour (KWH). On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, Alabama Power had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is 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 of the under recovered fuel costs.

Natural Disaster Reserve

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 Natural Disaster Reserve (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. 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.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2012 and December 31, 2011 were approximately $103 million and $110 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and Nuclear Construction Cost Recovery (NCCR) tariff adjustments described herein under "Fuel Cost Recovery" and "Nuclear Construction."

Under the 2010 ARP, Georgia Power's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011 or 2012. Georgia Power is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

On January 31, 2013, Georgia Power filed its triennial IRP (2013 IRP). The filing included 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.

Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 2013. 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 retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included Georgia Power's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, Georgia Power plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. Georgia Power also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. Georgia Power has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on Southern Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in Georgia Power's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. In addition, the Georgia PSC has authorized an IFR, which allows Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. Georgia Power expects to file its next fuel case by March 1, 2014.

Georgia Power's over recovered fuel balance totaled approximately $230 million at December 31, 2012 and is 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. As of December 31, 2012, the balance in the regulatory asset related to storm damage was $38 million. As a result of this regulatory treatment, the 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, Owners), entered into an agreement (Vogtle 3 and 4 Agreement) with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (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 (Plant Vogtle Units 3 and 4). Under the terms of the Vogtle 3 and 4 Agreement, the 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. Each 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%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain 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 Owners, Owner insolvency, and certain other events.

In 2009, the Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed Georgia Power, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost to approximately $4.4 billion.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, respectively. Through the NCCR tariff, Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

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, effective December 30, 2011, and issued combined construction and operating licenses (COLs) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. Georgia Power has intervened in, and intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

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. On February 19, 2013, the Georgia PSC voted to approve Georgia Power's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. 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. Accordingly, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 to $4.8 billion and to extend the estimated in-service dates to fourth quarter 2017 and fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

In July 2012, the 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 Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor has claimed that its estimated adjustment attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. The Contractor also has asserted it is entitled to further schedule extensions. Georgia Power has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. On November 1, 2012, Georgia Power and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against Georgia Power and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power 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.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power (on behalf of the 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.

Integrated Coal Gasification Combined Cycle

General

Mississippi Power is constructing a new electric generating facility located in Kemper County, Mississippi which will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs (Kemper IGCC). The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, Mississippi Power also plans to construct and operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County, Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed Mississippi Power to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC 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. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, 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 the ratepayers, relative to the original proposal for the CPCN).

Mississippi Power's current cost estimate for the Kemper IGCC (net of the $245 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the Mississippi Public Utilities Staff (MPUS) have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While Mississippi Power continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, Mississippi Power had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245 million of CCPI2 grant funds), $35 million was recorded in other regulatory assets, $4 million was recorded in other deferred charges and assets, and $1 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date.

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.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the Certificated New Plant-A (CNP-A) rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

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

Cost Recovery Plans

The 2012 MPSC 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. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by Mississippi Power and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with Mississippi Power to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, Mississippi Power submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55 million and $59 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by Mississippi Power, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC.

On July 9, 2012, Mississippi Power appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55 million. On July 31, 2012, the Mississippi Supreme Court denied Mississippi Power's request for interim rates under bond until the Mississippi Supreme Court decides Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, Mississippi Power and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to Mississippi Power and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves Mississippi Power's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted Mississippi Power and the Mississippi PSC's joint filing for dismissal of Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of Mississippi Power's request; (3) Mississippi Power's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. Mississippi Power contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, Mississippi Power, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of Mississippi Power's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, Mississippi Power proposes annual recovery to remain the same from 2014 through 2020 and, while it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement for certain items, Mississippi Power proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of the recovery. Mississippi Power proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, Mississippi Power has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement.

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

Tax Incentives

The IRS has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. Mississippi Power's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, Mississippi Power received or accrued tax benefits totaling $362 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be able to utilize $171 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, Mississippi Power filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by Mississippi Power may be subject to recapture upon successful completion of South Mississippi Electric Power Association's (SMEPA) purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if Mississippi Power fails to satisfy the in-service date requirements and carbon capture requirements described above.

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC.

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

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 in Kemper County. The mine is scheduled to be placed in service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163 million has been incurred through December 31, 2012.

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. Because Liberty Fuels conducts all of its activities on behalf of Mississippi Power, Liberty Fuels qualifies as a VIE for which Mississippi Power is the primary beneficiary. 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. Consistent with the requirements of consolidation accounting, Liberty Fuels is consolidated in the financial statements of Mississippi Power and accordingly the asset retirement cost and the asset retirement obligation have been recorded in Mississippi Power's financial statements. 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 will acquire, construct, and 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 estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78 million has been incurred through December 31, 2012.

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

Proposed Sale of Undivided Interest to SMEPA

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. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the deposit has been presented as a current liability in Southern Company's balance sheet herein and as financing proceeds in Southern Company's statement of cash flows herein.

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

Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). 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. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with Power South Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with 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 Florida Power Corporation 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, 2012, 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%	$ 3,327	$ 1,996	$ 67
Plant Hatch (nuclear)	50.1	1,037	551	49
Plant Miller (coal) Units 1 and 2	91.8	1,401	551	8
Plant Scherer (coal) Units 1 and 2	8.4	161	78	77
Plant Wansley (coal)	53.5	801	240	8
Rocky Mountain (pumped storage)	25.4	181	116	—
Intercession City (combustion turbine)	33.3	12	4	1
Plant Stanton (combined cycle) Unit A	65.0	156	36	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 to the financial statements 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 and combined state income tax returns for the States of Alabama, Georgia, Mississippi, and Texas. Under a joint consolidated income tax allocation agreement, each 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:

	2012	2011	2010
		(in millions)	
Federal —			
Current	$ 177	$ 57	$ 42
Deferred	1,011	1,035	898
	1,188	1,092	940
State —			
Current	61	8	(54)
Deferred	85	119	140
	146	127	86
Total	$ 1,334	$ 1,219	$ 1,026

Net cash payments/(refunds) for income taxes in 2012, 2011, and 2010 were $38 million, $(401) million, and $276 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:

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 9,022**	$ 7,882
Property basis differences	**1,254**	1,256
Leveraged lease basis differences	**278**	277
Employee benefit obligations	**536**	499
Under recovered fuel clause	**16**	82
Premium on reacquired debt	**84**	111
Regulatory assets associated with employee benefit obligations	**988**	1,198
Regulatory assets associated with asset retirement obligations	**1,108**	546
Other	**333**	276
Total	**13,619**	12,127
Deferred tax assets —		
Federal effect of state deferred taxes	**394**	393
Employee benefit obligations	**1,678**	1,594
Over recovered fuel clause	**135**	33
Other property basis differences	**134**	134
Deferred costs	**39**	55
Cost of removal	**29**	40
Tax credit carryforward	**256**	129
Unbilled revenue	**101**	110
Other comprehensive losses	**84**	81
Asset retirement obligations	**720**	546
Other	**362**	358
Total	**3,932**	3,473
Total deferred tax liabilities, net	**9,687**	8,654
Portion included in prepaid expenses (accrued income taxes), net	**237**	125
Deferred state tax assets	**68**	86
Valuation allowance	**(54)**	(56)
Accumulated deferred income taxes	**$ 9,938**	$ 8,809

At December 31, 2012, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $827 million, which could result in net state income tax benefits of $48 million, if utilized. However, the subsidiaries have established a valuation allowance for the potential $48 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2013 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, 2012, the tax-related regulatory assets to be recovered from customers were $1.4 billion. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2012, the tax-related regulatory liabilities to be credited to customers were $211 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits 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 $23 million in 2012, $19 million in 2011, and $23 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had not been utilized. The remaining investment tax credits will be carried forward and utilized in future years.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2012	2011	2010
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.4	1.8
Employee stock plans dividend deduction	**(1.0)**	(1.1)	(1.2)
Non-deductible book depreciation	**0.9**	0.7	0.8
Difference in prior years' deferred and current tax rate	**(0.1)**	(0.1)	(0.1)
AFUDC-Equity	**(1.3)**	(1.5)	(2.2)
ITC basis difference	**(0.3)**	(0.2)	(0.4)
Other	**(0.1)**	(0.2)	(0.2)
Effective income tax rate	**35.6%**	35.0%	33.5%

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.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $50 million, resulting in a balance of $70 million as of December 31, 2012.

Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 120**	$ 296	$ 199
Tax positions from current periods	**13**	46	62
Tax positions increase from prior periods	**7**	1	62
Tax positions decrease from prior periods	**(56)**	(111)	(27)
Reductions due to settlements	**(10)**	(112)	—
Reductions due to expired statute of limitations	**(4)**	—	—
Balance at end of year	**$ 70**	$ 120	$ 296

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The decreases in tax positions from prior periods primarily relate to state income tax credits and the 2009 MC Asset Recovery, LLC refund claim. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on Southern Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	$ 5	$ 69	$ 217
Tax positions not impacting the effective tax rate	65	51	79
Balance of unrecognized tax benefits	$ 70	$ 120	$ 296

The tax positions impacting the effective tax rate for 2012 primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with 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.

Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	$ 10	$ 29	$ 21
Interest reclassified due to settlements	(9)	(24)	—
Interest accrued during the year	—	5	8
Balance at end of year	$ 1	$ 10	$ 29

Southern Company classifies interest on tax uncertainties as interest expense. The interest reclassified due to settlements in 2012 is primarily associated with state income tax credits and a settlement with the IRS related to the calculation methodology for the production activities deduction.

Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of Southern Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, 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 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

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, 2012 and $206 million as of December 31, 2011, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2012 and 2011, trust preferred securities of $200 million and $200 million, respectively, 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:

	2012	2011
	(in millions)	
Senior notes	$ 2,085	$ 1,200
Other long-term debt	227	493
Capitalized leases	23	24
Total	$ 2,335	$ 1,717

Maturities through 2017 applicable to total long-term debt are as follows: $2.34 billion in 2013; $448 million in 2014; $2.44 billion in 2015; $1.37 billion in 2016; and $1.14 billion in 2017.

Bank Term Loans

Certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). At December 31, 2012, Mississippi Power had outstanding bank term loans totaling $175 million. At December 31, 2011, Mississippi Power had outstanding bank term loans totaling $240 million and Georgia Power had outstanding bank term loans totaling $450 million. Such amounts are reflected in the statements of capitalization as amounts due within one year.

During 2012, the traditional operating companies repaid approximately $565 million of floating rate bank notes bearing interest based on one-month LIBOR. In March 2012, Georgia Power paid at maturity a $250 million aggregate principal amount variable rate long-term bank note. In May 2012, Georgia Power repaid a $200 million aggregate principal amount variable rate short-term bank note due June 2012. In March 2012, Mississippi Power paid at maturity a $75 million aggregate principal amount variable rate long-term bank note. In September 2012, Mississippi Power paid at maturity a $40 million aggregate principal amount variable rate long-term bank note.

During 2012, Mississippi Power entered into a 366-day $100 million aggregate principal amount variable rate bank note bearing interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used for working capital and for other general corporate purposes, including Mississippi Power's continuous construction program.

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 the long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2012, Mississippi Power was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. Mississippi Power is currently in compliance with all such covenants.

Senior Notes

The traditional operating companies issued a total of $4.0 billion of senior notes in 2012. The proceeds of these issuances were used to repay approximately $2.8 billion of long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

At December 31, 2012 and 2011, Southern Company and its subsidiaries had a total of $17.4 billion and $15.9 billion, respectively, of senior notes outstanding. At December 31, 2012 and 2011, Southern Company had a total of $1.3 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 $3.4 billion and $3.4 billion of outstanding pollution control revenue bonds at December 31, 2012 and 2011, respectively. 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 October 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 21, 2021, issued for the benefit of the lessor. See Note 1 under "Property, Plant, and Equipment" and "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 August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.5 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of Mississippi Power. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of Mississippi Power. The 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. Any future issuances of the Series 2012A bonds will be used for this same purpose.

Mississippi Power had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2012 and 2011 and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2012. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Other Obligations

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the proposed sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies.

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. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $194 million as of December 31, 2012. 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.

In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value (with a fair value on the assumption date of $346 million) of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Property, Plant, and Equipment" for additional information.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

	Expires[(a)]					Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	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	158	350	800	1,308	1,308	56	—	56	102
Georgia Power	—	250	1,500	1,750	1,740	—	—	—	—
Gulf Power	80	195	—	275	275	45	—	45	35
Mississippi Power	135	165	—	300	300	25	40	65	70
Southern Power	—	—	500	500	500	—	—	—	—
Other	50	—	—	50	50	25	—	25	25
Total	$ 423	$ 960	$ 3,800	$ 5,183	$ 5,173	$ 151	$ 40	$ 191	$ 232

(a) No credit arrangements expire in 2015.

Most of the 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.

Most of the credit arrangements with banks 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 and, in certain arrangements, other hybrid securities. At December 31, 2012, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such 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 requiring liquidity support as of December 31, 2012 was approximately $1.8 billion.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[a]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2012:		
Commercial paper	**$ 820**	**0.3%**
December 31, 2011:		
Commercial paper	$ 654	0.3 %
Short-term bank debt	200	1.2 %
Total	$ 854	0.5 %

(a) Excludes notes payable related to other energy service contracts of $5 million and $6 million at December 31, 2012 and 2011, respectively.

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 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 that would allow the holders to elect a majority of such subsidiary's board. 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 required to be shown as "noncontrolling interest," separately presented as a 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, 2012 and 2011 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 2012, 2011, and 2010, the traditional operating companies and Southern Power incurred fuel expense of $5.1 billion, $6.3 billion, and $6.7 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 $171 million, $199 million, and $180 million for 2012, 2011, and 2010, respectively.

Estimated total obligations under these commitments at December 31, 2012 were as follows:

	PPAs	
	Operating Leases	Other
	(in millions)	
2013	$ 164	$ 24
2014	200	19
2015	249	11
2016	258	11
2017	263	8
2018 and thereafter	2,369	69
Total	$ 3,503	$ 142

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $155 million, $176 million, and $188 million for 2012, 2011, and 2010, 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, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2013	$ 71	$ 42	$ 113
2014	57	38	95
2015	24	29	53
2016	19	26	45
2017	11	21	32
2018 and thereafter	11	73	84
Total	$ 193	$ 229	$ 422

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 2018 with maximum obligations under these leases of $83 million. At the termination of the leases, the lessee may either 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

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2012, Southern Company issued 12.1 million shares of common stock for $397 million through employee and director stock plans. In 2011, Southern Company raised $723 million from the issuance of 21.9 million new common shares through the Southern Investment Plan and employee and director stock plans.

Stock Repurchased

In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. Under this program, approximately 9 million shares have been repurchased through December 31, 2012 at a total cost of $430 million. In January 2013, Southern Company announced that it planned to continue this program through 2015. Pursuant to Board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

Shares Reserved

At December 31, 2012, a total of 130 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 130 million shares reserved, there were 39 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2012.

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, 2012, there were 6,026 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. For certain stock option awards, a change in control will provide accelerated vesting.

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	**2012**	2011	2010
Expected volatility	**17.7%**	17.5%	17.4%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**0.9%**	2.3%	2.4%
Dividend yield	**4.2%**	4.8%	5.6%
Weighted average grant-date fair value	**$3.39**	$3.23	$2.23

Southern Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2011	40,956,822	$ 33.88
Granted	7,153,669	44.50
Exercised	(12,120,419)	32.76
Cancelled	(73,769)	37.75
Outstanding at December 31, 2012	**35,916,303**	**$ 36.37**
Exercisable at December 31, 2012	**22,724,015**	**$ 34.09**

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $243 million and $199 million, respectively.

As of December 31, 2012, there was $8 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 11 months.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $23 million, $22 million, and $22 million, respectively, with the related tax benefit also recognized in income of $9 million, $8 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $162 million, $155 million, and $57 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $62 million, $60 million, and $22 million for the years ended December 31, 2012, 2011, and 2010, 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, 2012, 2011, and 2010 was $397 million, $528 million, and $198 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.

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	**2012**	2011	2010
Expected volatility	**16.0%**	19.2%	20.7%
Expected term *(in years)*	**3.0**	3.0	3.0
Interest rate	**0.4%**	1.4%	1.4%
Annualized dividend rate	**$1.89**	$1.82	$1.75
Weighted average grant-date fair value	**$41.99**	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 1,719,598. During 2012, 842,447 performance share units were granted, 842,710 performance share units were vested, and 86,179 performance share units were forfeited resulting in 1,633,156 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 1,137,817 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $28 million, $18 million, and $9 million, respectively, with the related tax benefit also recognized in income of $11 million, $7 million, and $4 million, respectively. As of December 31, 2012, there was $33 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 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		
	2012	2011	2010
	(in millions)		
As reported shares	**871**	857	832
Effect of options and performance share award units	**8**	7	5
Diluted shares	**879**	864	837

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were immaterial as of December 31, 2012 and 2011. Assuming an average stock price of $47.89 and $42.67 (the highest exercise prices of the anti-dilutive options outstanding in 2012 and 2011, respectively), the effect of options and performance share award units would have been immaterial for the years ended December 31, 2012 and 2011.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2012, 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 $12.6 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 $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 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 $235 million and $232 million, respectively, per incident, but not more than an aggregate of $35 million 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 October 29, 2013. See Note 4 to the financial statements 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 $500 million for members' operating nuclear generating facilities. Additionally, both companies have policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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 the maximum limit allowed by NEIL, 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 if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $42 million and $70 million, respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2012, 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, 2012:	**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	$ —	$ 26	$ —	$ 26
Interest rate derivatives	—	10	—	10
Nuclear decommissioning trusts:[(a)]				
Domestic equity	453	65	—	518
Foreign equity	28	172	—	200
U.S. Treasury and government agency securities	—	134	—	134
Municipal bonds	—	55	—	55
Corporate bonds	—	234	—	234
Mortgage and asset backed securities	—	141	—	141
Other investments	—	20	—	20
Cash equivalents	384	—	—	384
Other investments	9	—	15	24
Total	$ 874	$ 857	$ 15	$ 1,746
Liabilities:				
Energy-related derivatives	$ —	$ 111	$ —	$ 111

(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, 2011, 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, 2011:	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	$ —	$ 14	$ —	$ 14
Interest rate derivatives	—	13	—	13
Foreign currency derivatives	—	2	—	2
Nuclear decommissioning trusts:[(a)]				
Domestic equity	396	58	—	454
Foreign equity	124	48	—	172
U.S. Treasury and government agency securities	17	33	—	50
Municipal bonds	—	82	—	82
Corporate bonds	—	260	—	260
Mortgage and asset backed securities	—	151	—	151
Other investments	—	36	—	36
Cash equivalents and restricted cash	1,024	—	—	1,024
Other investments	3	50	14	67
Total	$ 1,564	$ 747	$ 14	$ 2,325
Liabilities:				
Energy-related derivatives	$ —	$ 245	$ —	$ 245
Interest rate derivatives	—	33	—	33
Foreign currency derivatives	—	3	—	3
Total	$ —	$ 281	$ —	$ 281

(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 LIBOR interest rates. Interest rate and foreign currency 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. Inputs for foreign currency derivatives are from observable market sources. See Note 11 for additional information on how these derivatives are used.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.

For fair value measurements of investments within the nuclear decommissioning trusts and rabbi trust funds, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts and rabbi trust funds with each security discriminately assigned a primary pricing source, based on similar characteristics.

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, 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, 2012 and 2011, 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, 2012:	*(in millions)*			
Nuclear decommissioning trusts:				
Foreign equity funds	$ 117	None	Monthly	5 days
Corporate bonds – commingled funds	9	None	Daily	Not applicable
Equity – commingled funds	55	None	Daily/Monthly	Daily/7 days
Other – commingled funds	10	None	Daily	Not applicable
Trust-owned life insurance	96	None	Daily	15 days
Cash equivalents:				
Money market funds	384	None	Daily	Not applicable
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 32	None	Daily	Not applicable
Equity – commingled funds	48	None	Daily/Monthly	Daily/7 days
Other – commingled funds	25	None	Daily	Not applicable
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	1,024	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds to comply with the NRC's regulations. 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 and depository receipts, including American depositary receipts, European depositary receipts and global depository 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 commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio, including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The commingled funds included within corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

Alabama Power's nuclear decommissioning trust includes investments in TOLI. The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio 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 trust does 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. The commingled funds 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, to some degree, 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 Securities and Exchange Commission 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, 2012 and 2011, 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:		
2012	**$ 21,530**	**$ 23,480**
2011	$ 20,272	$ 22,144

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.

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. Southern Power 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, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

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, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company	276	2017	2017

* million British thermal units

In addition to the volumes discussed in the table 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 OCI to revenue and fuel expense for the next 12-month period ending December 31, 2013 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, 2012, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid*	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2012
	(in millions)				(in millions)
Fair value hedges of existing debt					
Southern Company	$ 350	4.15%	3-month LIBOR + 1.96% spread	May 2014	$ 10

* Weighted Average

For the year ended December 31, 2012, the Company had realized net losses of $52 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings. The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $14 million. 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 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 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. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. At December 31, 2012, the fair value of the foreign currency derivative outstanding was immaterial.

Derivative Financial Statement Presentation and Amounts

At December 31, 2012 and 2011, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 10**	$ 9	Liabilities from risk management activities	**$ 74**	$ 163
	Other deferred charges and assets	**13**	5	Other deferred credits and liabilities	**35**	72
Total derivatives designated as hedging instruments for regulatory purposes		**$ 23**	$ 14		**$ 109**	$ 235
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Liabilities from risk management activities	**$ —**	$ 1
Interest rate derivatives:	Other current assets	**7**	6	Liabilities from risk management activities	**—**	33
	Other deferred charges and assets	**3**	7	Other deferred credits and liabilities	**—**	—
Foreign currency derivatives:	Other current assets	**—**	—	Liabilities from risk management activities	**—**	1
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 10**	$ 13		**$ —**	$ 35
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ 1**	$ —	Liabilities from risk management activities	**$ 1**	$ 9
	Other deferred charges and assets	**2**	—	Other deferred credits and liabilities	**1**	—
Foreign currency derivatives:	Other current assets	**—**	2	Liabilities from risk management activities	**—**	2
Total derivatives not designated as hedging instruments		**$ 3**	$ 2		**$ 2**	$ 11
Total		**$ 36**	$ 29		**$ 111**	$ 281

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2012 and 2011, 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**	**2012**	2011	**Balance Sheet Location**	**2012**	2011
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (74)**	$ (163)	Other regulatory liabilities, current	**$ 10**	$ 9
	Other regulatory assets, deferred	**(35)**	(72)	Other regulatory liabilities, deferred	**13**	5
Total energy-related derivative gains (losses)		**$ (109)**	$ (235)		**$ 23**	$ 14

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were as follows:

Derivatives in Fair Value Hedging Relationships				
		Amount		
Derivative Category	**Statements of Income Location**	**2012**	2011	2010
			(in millions)	
Interest rate derivatives:	Interest expense	**$ (3)**	$ 3	$ 10
Foreign currency derivatives:	Other operations and maintenance	**1**	(4)	3
Total		**$ (2)**	$ (1)	$ 13

For the years ended December 31, 2012, 2011, and 2010, 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; there was no material impact on Southern Company's statements of income.

For the years ended December 31, 2012, 2011, and 2010, 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; therefore, there was no material impact on Southern Company's statements of income.

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of 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	**2012**	2011	2010	**Statements of Income Location**	**2012**	2011	2010
		(in millions)				*(in millions)*	
Energy-related derivatives	**$ —**	$ —	$ 1	Fuel	**$ —**	$ —	$ —
Interest rate derivatives	**(19)**	(28)	(3)	Interest expense, net of amounts capitalized	**(18)**	(14)	(25)
Foreign currency derivatives	**—**	—	1	Other operations and maintenance	**—**	—	1
				Other income (expense), net	**—**	(1)	—
Total	**$ (19)**	$ (28)	$ (1)		**$ (18)**	$ (15)	$ (24)

There was no material ineffectiveness recorded in earnings for any period presented.

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a substantial 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 immaterial for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2012, the fair value of derivative liabilities with contingent features was $15 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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.

12. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $425 million, $359 million, and $371 million in 2012, 2011, and 2010, 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 intersegment revenues are not material. Financial data for business segments and products and services was as follows:

	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)*	**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**
2011							
Operating revenues	$ 16,763	$ 1,236	$ (412)	$ 17,587	$ 149	$ (79)	$ 17,657
Depreciation and amortization	1,576	124	—	1,700	16	1	1,717
Interest income	18	1	—	19	3	(1)	21
Interest expense	726	77	—	803	54	—	857
Income taxes	1,217	76	—	1,293	(74)	—	1,219
Segment net income (loss)*	2,052	162	—	2,214	(8)	(3)	2,203
Total assets	54,622	3,581	(127)	58,076	1,592	(401)	59,267
Gross property additions	4,589	255	—	4,844	9	—	4,853
2010							
Operating revenues	$ 16,712	$ 1,130	$ (468)	$ 17,374	$ 162	$ (80)	$ 17,456
Depreciation and amortization	1,376	119	—	1,495	18	—	1,513
Interest income	22	—	—	22	3	(1)	24
Interest expense	757	76	—	833	63	(1)	895
Income taxes	1,039	75	—	1,114	(89)	1	1,026
Segment net income (loss)*	1,860	131	—	1,991	(11)	(5)	1,975
Total assets	51,144	3,438	(128)	54,454	1,178	(600)	55,032
Gross property additions	4,029	405	—	4,434	9	—	4,443

* After dividends on preferred and preference stock of subsidiaries.

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2012	**$ 14,187**	**$ 1,675**	**$ 616**	**$ 16,478**
2011	$ 15,071	$ 1,905	$ 611	$ 17,587
2010	$ 14,791	$ 1,994	$ 589	$ 17,374

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2012 and 2011 is as follows:

				Per Common Share			
						Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Basic Earnings	Dividends	High	Low
		(in millions)					
March 2012	**$ 3,604**	**$ 766**	**$ 368**	**$ 0.42**	**$ 0.4725**	**$ 46.06**	**$ 43.71**
June 2012	**4,181**	**1,143**	**623**	**0.71**	**0.4900**	**48.45**	**44.22**
September 2012	**5,049**	**1,740**	**976**	**1.11**	**0.4900**	**48.59**	**44.64**
December 2012	**3,703**	**814**	**383**	**0.44**	**0.4900**	**47.09**	**41.75**
March 2011	$ 4,012	$ 854	$ 422	$ 0.50	$ 0.4550	$ 38.79	$ 36.51
June 2011	4,521	1,136	604	0.71	0.4725	40.87	37.43
September 2011	5,428	1,652	916	1.07	0.4725	43.09	35.73
December 2011	3,696	589	261	0.30	0.4725	46.69	41.00

The Southern Company system's business is influenced by seasonal weather conditions.

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		2012		2011		2010		2009		2008
Operating Revenues (in millions)	$	**16,537**	$	17,657	$	17,456	$	15,743	$	17,127
Total Assets (in millions)	$	**63,149**	$	59,267	$	55,032	$	52,046	$	48,347
Gross Property Additions (in millions)	$	**5,059**	$	4,853	$	4,443	$	4,913	$	4,122
Return on Average Common Equity (percent)		**13.10**		13.04		12.71		11.67		13.57
Cash Dividends Paid Per Share of Common Stock	$	**1.9425**	$	1.8725	$	1.8025	$	1.7325	$	1.6625
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	$	**2,350**	$	2,203	$	1,975	$	1,643	$	1,742
Earnings Per Share —										
Basic	$	**2.70**	$	2.57	$	2.37	$	2.07	$	2.26
Diluted		**2.67**		2.55		2.36		2.06		2.25
Capitalization (in millions)**:**										
Common stock equity	$	**18,297**	$	17,578	$	16,202	$	14,878	$	13,276
Preferred and preference stock of subsidiaries		**707**		707		707		707		707
Redeemable preferred stock of subsidiaries		**375**		375		375		375		375
Long-term debt		**19,274**		18,647		18,154		18,131		16,816
Total (excluding amounts due within one year)	$	**38,653**	$	37,307	$	35,438	$	34,091	$	31,174
Capitalization Ratios (percent)**:**										
Common stock equity		**47.3**		47.1		45.7		43.6		42.6
Preferred and preference stock of subsidiaries		**1.8**		1.9		2.0		2.1		2.3
Redeemable preferred stock of subsidiaries		**1.0**		1.0		1.1		1.1		1.2
Long-term debt		**49.9**		50.0		51.2		53.2		53.9
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	$	**21.09**	$	20.32	$	19.21	$	18.15	$	17.08
Market price per share:										
High	$	**48.59**	$	46.69	$	38.62	$	37.62	$	40.60
Low		**41.75**		35.73		30.85		26.48		29.82
Close (year-end)		**42.81**		46.29		38.23		33.32		37.00
Market-to-book ratio (year-end) (percent)		**203.0**		227.8		199.0		183.6		216.6
Price-earnings ratio (year-end) (times)		**15.9**		18.0		16.1		16.1		16.4
Dividends paid (in millions)	$	**1,693**	$	1,601	$	1,496	$	1,369	$	1,279
Dividend yield (year-end) (percent)		**4.5**		4.0		4.7		5.2		4.5
Dividend payout ratio (percent)		**72.0**		72.7		75.7		83.3		73.5
Shares outstanding (in thousands):										
Average		**871,388**		856,898		832,189		794,795		771,039
Year-end		**867,768**		865,125		843,340		819,647		777,192
Stockholders of record (year-end)		**149,628**		155,198		160,426 *		92,799		97,324
Traditional Operating Company Customers (year-end) (in thousands):										
Residential		**3,832**		3,809		3,813		3,798		3,785
Commercial		**580**		579		580		580		594
Industrial		**15**		15		15		15		15
Other		**9**		9		9		9		8
Total		**4,436**		4,412		4,417		4,402		4,402
Employees (year-end)		**26,439**		26,377		25,940		26,112		27,276

* In July 2010, Southern Company changed its transfer agent from Southern Company Services, Inc. to Mellon Investor Services LLC (n/k/a Computershare Shareowner Services, LLC). The change in the number of stockholders of record is primarily attributed to the calculation methodology used by Mellon Investor Services LLC.

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	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$ 5,891	$ 6,268	$ 6,319	$ 5,481	$ 5,476
Commercial	5,097	5,384	5,252	4,901	5,018
Industrial	3,071	3,287	3,097	2,806	3,445
Other	128	132	123	119	116
Total retail	14,187	15,071	14,791	13,307	14,055
Wholesale	1,675	1,905	1,994	1,802	2,400
Total revenues from sales of electricity	15,862	16,976	16,785	15,109	16,455
Other revenues	675	681	671	634	672
Total	$ 16,537	$ 17,657	$ 17,456	$ 15,743	$ 17,127
Kilowatt-Hour Sales (in millions):					
Residential	50,454	53,341	57,798	51,690	52,262
Commercial	53,007	53,855	55,492	53,526	54,427
Industrial	51,674	51,570	49,984	46,422	52,636
Other	919	936	943	953	934
Total retail	156,054	159,702	164,217	152,591	160,259
Wholesale sales	27,563	30,345	32,570	33,503	39,368
Total	183,617	190,047	196,787	186,094	199,627
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.68	11.75	10.93	10.60	10.48
Commercial	9.62	10.00	9.46	9.16	9.22
Industrial	5.94	6.37	6.20	6.04	6.54
Total retail	9.09	9.44	9.01	8.72	8.77
Wholesale	6.08	6.28	6.12	5.38	6.10
Total sales	8.64	8.93	8.53	8.12	8.24
Average Annual Kilowatt-Hour Use Per Residential Customer	13,187	13,997	15,176	13,607	13,844
Average Annual Revenue Per Residential Customer	$ 1,540	$ 1,645	$ 1,659	$ 1,443	$ 1,451
Plant Nameplate Capacity Ratings (year-end) (megawatts)	45,740	43,555	42,961	42,932	42,607
Maximum Peak-Hour Demand (megawatts):					
Winter	31,705	34,617	35,593	33,519	32,604
Summer	35,479	36,956	36,321	34,471	37,166
System Reserve Margin (at peak) (percent)	20.8	19.2	23.3	26.4	15.3
Annual Load Factor (percent)	59.5	59.0	62.2	60.6	58.7
Plant Availability (percent)*:					
Fossil-steam	89.4	88.1	91.4	91.3	90.5
Nuclear	94.2	93.0	92.1	90.1	91.3
Source of Energy Supply (percent):					
Coal	35.2	48.7	55.0	54.7	64.0
Nuclear	16.2	15.0	14.1	14.9	14.0
Hydro	1.7	2.1	2.5	3.9	1.4
Oil and gas	38.3	28.0	23.7	22.5	15.4
Purchased power	8.6	6.2	4.7	4.0	5.2
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

MANAGEMENT COUNCIL

1. Thomas A. Fanning

Chairman, President, and Chief Executive Officer

Fanning, 56, joined the Company as a Financial Analyst in 1980. He has held his current position since December 2010. Previously, Fanning served as the Company's Executive Vice President and Chief Operating Officer from 2008 to 2010 with responsibility for Southern Company Generation, Southern Power, and Southern Company Transmission, as well as leading Southern Company's efforts on business strategy and associated planning issues. He has also served as President and Chief Executive Officer of Gulf Power and Chief Financial Officer for Southern Company, Georgia Power, and Mississippi Power.

2. Art P. Beattie

Executive Vice President and Chief Financial Officer

Beattie, 58, 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

President and Chief Executive Officer of Georgia Power

Bowers, 56, 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 Executive Vice President and Chief Financial Officer of the Company, President of Southern Company Generation and President and Chief Executive Officer of Southern Power, President and Chief Executive Officer of Southern Company's former United Kingdom subsidiary, and Senior Vice President and Chief Marketing Officer for Southern Company.

4. S. W. Connally, Jr.

President and Chief Executive Officer of Gulf Power

Connally, 43, 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 Chief 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 Chief Operating Officer

Crosswhite, 50, joined the Company in 2004 as Senior Vice President and General Counsel for Southern Company Generation. He has held his current position since July 2012. He previously served as President and Chief Executive Officer of Gulf Power and Executive Vice President of External Affairs and Senior Vice President and 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. Edward Day, VI

President and Chief Executive Officer of Mississippi Power

Day, 52, joined the Company as an Engineer with Georgia Power in 1983. He has held his current position since August 2010. Previously, Day served as Executive Vice President of Engineering and Construction Services for Southern Company Generation. He has held positions in a number of functional areas within the Company, including nuclear, wholesale power marketing, engineering, procurement, and construction.

7. Kimberly S. Greene

President and Chief Executive Officer, Southern Company Services, Inc.

Greene, 46, has held her current role since April 2013. Prior to that, she was employed by Tennessee Valley Authority, where she served as Chief Financial Officer, Group President of Strategy and External Relations, and, most recently, Chief Generation Officer. Greene also 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.

8. G. Edison Holland, Jr.

Executive Vice President, General Counsel, and Corporate Secretary

Holland, 60, joined the Company as Vice President and Corporate Counsel for Gulf Power in 1992. He was named to his current position, which includes serving as the Chief Compliance Officer, in April 2001. Previously, he was President and Chief Executive Officer of Savannah Electric and Power Company and Vice President of Power Generation and Transmission at Gulf Power.

9. Stephen E. Kuczynski

Chairman, President and Chief Executive Officer of Southern Nuclear

Kuczynski, 50, joined the Company in July 2011 as Chairman, President, and Chief Executive Officer of Southern Nuclear. From 2006 to 2011, he was Senior Vice President of Engineering and Technical Services for Exelon Nuclear. Previously, he served as Senior Vice President of Midwest operations for Exelon Nuclear, with oversight of its 11 Illinois nuclear units. Kuczynski has more than 27 years of experience in the nuclear industry.

10. Charles D. McCrary

Executive Vice President

President and Chief Executive Officer of Alabama Power

McCrary, 61, joined the Company as an Assistant Project Planning Engineer with Alabama Power in 1973. He assumed his current position in 2001. Previously, McCrary was Chief Production Officer for Southern Company and President and Chief Executive Officer of Southern Power. He has held executive positions at Alabama Power and Southern Nuclear as well as various jobs in engineering, system planning, fuels, and environmental affairs.

11. Christopher C. Womack

Executive Vice President and

President, External Affairs

Womack, 55, 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 held numerous executive and management positions including the 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 15 through 21 of the attached Proxy Statement.

STOCKHOLDER INFORMATION

Transfer Agent
Computershare Shareowner Services, LLC (Computershare Shareowner Services) 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
The Southern Company
c/o Computershare Shareowner Services
P.O. Box 43006
Providence, RI 02940-3006

By Courier
The Southern Company
c/o Computershare Shareowner Services
250 Royall Street
Canton, MA 02021

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

Computershare Shareowner Services Internet Site
To take advantage of Computershare Shareowner Services' 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 2012 is taxable. The Board of Directors sets the record and payment dates for quarterly dividends. A dividend of 49 cents per share was paid in March 2013. For the remainder of 2013, projected record dates are May 6, August 5, and November 4. Projected payment dates for dividends declared during the remainder of 2013 are June 6, September 6, and December 6.

Auditors
Deloitte & Touche LLP
191 Peachtree St. NE
Suite 2000
Atlanta, GA 30303

During 2012, there were no changes in or disagreements with the auditors on accounting and financial disclosure.

Investor Information Line
For recorded information about earnings and dividends, stock quotes, and current news releases, call toll-free 866-762-6411.

Institutional Investor Inquiries
Southern Company maintains an investor relations office in Atlanta, 404-506-0571, 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:

Chris Hobson
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 common stock is listed on the New York Stock Exchange under the ticker symbol SO. On December 31, 2012, Southern Company had 149,628 stockholders of record.

SOUTHERN COMPANY

Recycled Paper