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Notice of 2012 Annual Meeting of Stockholders and Proxy Statement

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 2012 Annual Meeting of Stockholders at 10:00 a.m. ET on Wednesday, May 23, 2012, at The Lodge Conference Center at Callaway Gardens, Pine Mountain, Georgia.

At last year's meeting, I introduced five distinct priorities for the next few years:

- Stick to the fundamentals;
- Achieve success with major construction projects;
- Support the building of a national energy policy;
- Promote smart energy; and
- Value and develop our people.

We have made excellent progress toward achieving these five priorities and are continuing the proud legacy initiated by our founders 100 years ago. In this, the year of Southern Company's centennial celebration, we continue to honor the past and build for the future, with an unyielding commitment to provide safe, clean, reliable, and affordable electricity for generations to come.

At the annual meeting, I will report on our accomplishments from 2011, as well as our plans for 2012 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 B, the 2011 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 23rd. 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 23, 2012

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 2012;
3. To approve on a non-binding advisory basis The Southern Company's named executive officers' compensation;
4. To consider a stockholder proposal on a coal combustion byproducts environmental report;
5. To consider a stockholder proposal on a lobbying contributions and expenditures report; and
6. 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 26, 2012 are entitled to attend and vote at the meeting.

Annual Report to Stockholders

Appendix B to this Proxy Statement is Southern Company's 2011 Annual Report.

By Order of the Board of Directors, G. Edison Holland, Jr., Corporate Secretary, April 13, 2012

Voting Information

Even if you plan to attend the meeting in person, please provide your voting instructions in one of the following ways as soon as possible by the internet, the phone using the toll-free number, or the 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 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 13, 2012.

Q: Who can vote?

A: All stockholders of record at the close of business on the record date of March 26, 2012 may vote. On that date, there were 869,216,438 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 such broker, bank, or nominee to instruct such 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 important 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 2012 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 a broker fails to vote are not counted toward a quorum. Neither abstentions, broker non-votes, nor shares that brokers fail to vote are counted for or against the matters being considered.

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 www.southerncompany.com to view the 2012 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 2011 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 2011 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 2011 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 of Item No. 1, 2, and 3 and "AGAINST" each of Item No. 4 and 5.

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 5.

Q: When are stockholder proposals due for the 2013 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 2013 Annual Meeting of Stockholders is December 14, 2012. 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 27, 2013.

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 officers or other employees of the Company or its subsidiaries may solicit proxies to have a larger representation at the meeting. The Company has retained Alliance Advisors LLC to assist with the solicitation of proxies for a fee not to exceed $8,000, plus reimbursement of out-of-pocket expenses.

Important Notice Regarding the Availability of Proxy Materials for the 2012 Annual Meeting of Stockholders to be held on May 23, 2012:

The Company's 2012 Proxy Statement, which includes the 2011 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 2011 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 2012 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 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
- Overview of Southern Company Policies and Practices for Political Spending
- Overview of Southern Company Policies and Practices for Lobbying-Related Activities
- By-Laws of the Company
- Executive Stock Ownership Requirements
- Board Committee Charters
- Board of Directors — Background and Experience
- Management Council — Background and Experience
- SEC filings
- Composition of Board Committees
- Link for on-line communication with Board of Directors

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.
- The Director was employed, or the Director's immediate family member was employed, as an executive officer of a company where any of the Company's present executive officers serves 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 on page 66 of this Proxy Statement. Mr. Donald M. James is the Chief Executive Officer of Vulcan Materials Company. Mr. E. Jenner Wood III is the Chairman, President, and Chief Executive Officer of the Atlanta/ Georgia 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.

No Director or immediate family member of a Director serves in an executive capacity for a charitable organization. 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 similar contributions 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 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, 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; 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 2011, 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	—	—	1,800	219,300
Jon A. Boscia	100,000	105,000	—	—	587	205,587
Henry A. Clark III	112,500	105,000	—	—	1,666	219,166
H. William Habermeyer, Jr.	112,500	105,000	—	—	1,070	218,570
Veronica M. Hagen	100,000	105,000	—	—	1,611	206,611
Warren A. Hood, Jr.	100,000	105,000	—	—	1,517	206,517
Donald M. James	112,500	105,000	—	—	546	218,046
Dale E. Klein	100,000	105,000	—	—	1,548	206,548
J. Neal Purcell	112,500	105,000	—	—	1,633	219,133
William G. Smith, Jr.	112,500	105,000	—	—	1,977	219,477
Steven R. Specker	100,000	105,000	—	—	2,199	207,199
Larry D. Thompson	100,000	105,000	—	—	1,522	206,522

(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.

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 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. James was appointed to serve as the Presiding Director effective January 1, 2010 until December 31, 2011. In December 2011, the Board extended his term as the Presiding Director through May 23, 2012 in order to better align the term with the 2012 Annual Meeting of Stockholders. The Presiding Director is selected bi-annually by and from the independent Directors. Non-management Directors meet, without management, at least quarterly, and at other times as deemed appropriate by the Presiding Director or two or more other independent Directors. As the Presiding Director, Mr. James 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 contact Director for stockholders. The Presiding Director will also be 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 with no member 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. Smith *(Chair),* Mr. Boscia, Mr. Hood, and Mr. Thompson
- Met 10 times in 2011
- 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. Smith qualifies as an "audit committee financial expert" as defined by the SEC.

Compensation and Management Succession Committee (Compensation Committee):

- Current members are Mr. Purcell *(Chair)*, Mr. Clark, Mr. Habermeyer, and Mr. James
- Met eight times in 2011
- 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 2011, 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 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

In 2011, the Compensation Committee directly retained Pay Governance LLC as its independent compensation consultant. The Compensation Committee informed Pay Governance LLC that it expected Pay Governance LLC to provide an independent assessment of the current executive compensation program and any management-recommended changes to that program and to work with Southern 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 LLC to advise on executive compensation and related corporate governance trends.

During 2011, Pay Governance LLC 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. Purcell
- Met seven times in 2011
- 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*), Ms. Hagen, Dr. Klein, and Dr. Specker
- Met five times in 2011
- 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 14, 2012 for consideration by the Governance Committee as a nominee for election at the Annual Meeting of Stockholders to be held in 2013. 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 would consider aspects of diversity, such as diversity of age, race, gender, education, industry, and public and private service 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, 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. E. Jenner Wood III was recommended by the Governance Committee for nomination for election to the Board and was selected as a nominee for election as a Director. Mr. Wood was identified jointly by management and the members of the Governance Committee.

Nuclear/Operations Committee:

- Current members are Mr. Habermeyer (*Chair*), Ms. Baranco, Ms. Hagen, Dr. Klein, and Dr. Specker
- Met five times in 2011
- Oversees significant information, activities, and events relative to significant operations of the Company including nuclear and other generation facilities, transmission and distribution, fuel, and information technology initiatives
- Provides information to the Compensation Committee on the Company'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 broadly designate 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 also is responsible for reviewing the adequacy of the risk oversight process and for reviewing documentation demonstrating 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. 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 2011. Average Director attendance at all Board and committee meetings was 97%. No nominee attended less than 75% of applicable meetings.

All Director nominees are expected to attend the Annual Meeting of Stockholders. All the members of the Board of Directors serving on May 25, 2011, the date of the 2011 Annual Meeting of Stockholders, attended the meeting.

RETIRING DIRECTOR

Mr. J. Neal Purcell, who has served as a Director of the Company since 2003, is retiring from the Board effective May 23, 2012. During his time on the Board, Mr. Purcell has chaired the Audit Committee and the Compensation Committee and has been a member of the Finance Committee. Mr. Purcell also served as the Company's first audit committee financial expert. He is a retired Vice-Chairman of KPMG. From October 1998 until his retirement in 2002, Mr. Purcell was in charge of National Audit Practice Operations. Mr. Purcell is currently a Director of Kaiser Permanente Health Care and Hospitals and Synovus Financial Corp., where he is serves as the Chair of each Audit Committee. He also serves on the Board of Trustees of Emory University, where he is Chair of the Compensation Committee and on the Board of Directors of Emory Healthcare System. His financial and accounting expertise, his knowledge of the communities served by the Company's subsidiaries, and his personal involvement in those communities have been valuable to the Board.

Stock Ownership Table

STOCK OWNERSHIP OF DIRECTORS, NOMINEES, AND EXECUTIVE OFFICERS

The following table shows the number of shares of Common Stock owned by Directors, nominees, and executive officers as of December 31, 2011. 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.

Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Shares Beneficially Owned Include: Deferred Common Stock Units (2)	Shares Individuals Have Rights to Acquire within 60 days (3)	Shares Held by Family Members (4)
Juanita Powell Baranco	36,209	35,634		
Art P. Beattie	177,279		171,397	127
Jon A. Boscia	70,819	11,819		
W. Paul Bowers	597,115		585,310	
Henry A. Clark III	6,291	6,291		
Thomas A. Fanning	950,873		939,586	
H. William Habermeyer, Jr.	13,633	13,633		
Veronica M. Hagen	17,525	17,525		
Warren A. Hood, Jr.	27,539	26,962		
Donald M. James	71,831	71,831		
Dale E. Klein	3,762	3,762		
Charles D. McCrary	609,103		602,965	
J. Neal Purcell (5)	61,607	51,383		224
William G. Smith, Jr.	40,407	35,219		372
Steven R. Specker	3,105	3,105		
Larry D. Thompson	7,060	7,060		
Anthony J. Topazi	315,391		298,643	
E. Jenner Wood III (6)	9,496	8,443		
Directors, Nominees, and Executive Officers as a Group (24 people)	4,235,541	292,667	3,791,348	723

(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.

(5) Mr. Purcell's retirement from the Board will be effective May 23, 2012.

(6) Mr. Wood is a nominee for election to the Board.

STOCK OWNERSHIP OF CERTAIN OTHER BENEFICIAL OWNERS

According to a Schedule 13G/A and a Schedule 13G filed with the SEC on February 13, 2012 and February 9, 2012, respectively, (the Ownership Reports), the following reported beneficial ownership of more than 5% of the outstanding shares of Common Stock:

Title of Class	Name and Address	Shares Beneficially Owned	Percentage of Class Owned
Common Stock	Blackrock, Inc. 40 East 52nd Street New York, NY 10022	53,227,198	6.18%
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	43,426,176	5.00%

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

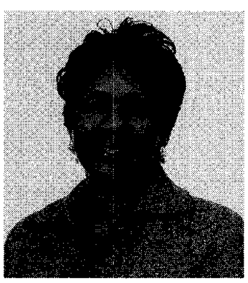
Matters to be Voted Upon

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 2013 Annual Meeting of Stockholders.

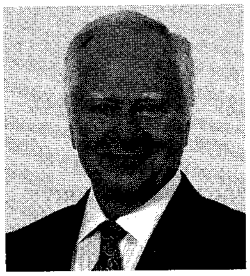
The Board of Directors, acting upon the recommendation of the Governance Committee, nominates the following individuals for election to the Southern Company Board of Directors. Each nominee holds or has held senior executive positions, maintains the highest degree of integrity and ethical standards, 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, and corporate governance 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 community involvement, as well as the number of other board memberships each holds.



Juanita Powell Baranco

Age:	63
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)

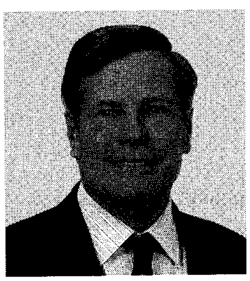
Director qualifications: Ms. Baranco had a successful law career, which included serving as Assistant Attorney General for the State of Georgia, before she and her husband founded the first Baranco dealership in Atlanta in 1978. She served as a Director on the Board of Georgia Power Company (Georgia 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. 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 benefitted from Ms. Baranco's particular expertise in business operations and her civic involvement.



Jon A. Boscia

Age:	59
Director since:	2007
Board committee:	Audit
Other directorships:	Sun Life Financial Inc. (formerly a Director of Armstrong World Industries, Lincoln Financial Group, Georgia Pacific Corporation, and The Hershey Company)

Director qualifications: From September 2008 until his retirement in 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. Following his retirement, Mr. Boscia was asked to serve on the Board of Sun Life Financial Inc., where he is a member of the Investment Oversight Committee and the Risk Review Committee. 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. 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, and information technology are valuable to the Board.



Henry A. "Hal" Clark III

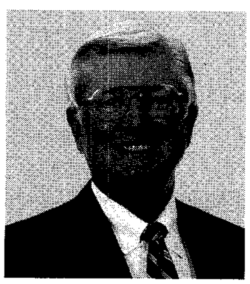
Age:	62
Director since:	2009
Board committees:	Finance (*Chair*), Compensation and Management Succession
Principal occupation:	Senior Advisor of Evercore Partners Inc. (formerly Lexicon Partners, LLC), corporate finance advisory firm, since July 2009
Other directorships:	None

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, convertibles, 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:	55
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 (formerly a Director of The St. Joe Company)

Director qualifications: Mr. Fanning had held numerous leadership positions across the Southern Company system during his more than 30 years with the Company. More recently, 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. Prior to that, 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.



H. William Habermeyer, Jr.

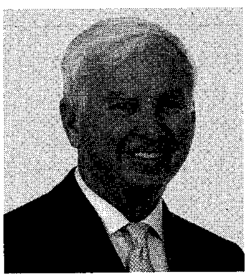
Age:	69
Director since:	2007
Board committees:	Nuclear/Operations (*Chair*), Compensation and Management Succession
Other directorships:	Raymond James Financial Inc., USEC Inc.

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 Compensation 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. "Ronee" Hagen

Age:	66
Director since:	2008
Board committees:	Governance, Nuclear/Operations
Principal occupation:	Chief Executive Officer of Polymer Group, Inc., engineered materials
Other directorships:	Polymer Group, Inc., Newmont Mining Corporation

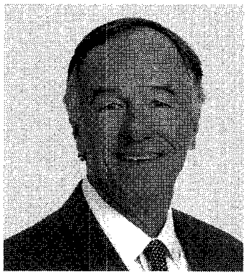
Director qualifications: Ms. Hagen's global operational management experience and commercial business leadership are valuable assets to the Board. Polymer Group, Inc. is a leading producer and marketer of engineered materials. Prior to joining Polymer Group, Inc., Ms. Hagen was the President and Chief 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 and Social Responsibility, Operations and Safety Committee and the Compensation Committee of the Board of Newmont Mining Corporation.



Warren A. Hood, Jr.

Age:	60
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 Bank (formerly a Director of Mississippi Power Company)

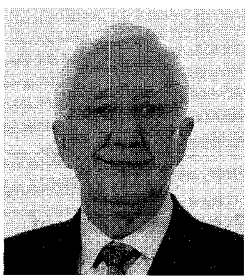
Director qualifications: Mr. Hood is the Chairman and Chief Executive Officer of Hood Companies Inc. which he established in 1978. Hood Companies Inc. consists of four separate corporations with 60 manufacturing and distribution sites throughout the United States, Canada, and Mexico. Mr. Hood previously 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 BancorpSouth Bank, Boy Scouts of America, and The Governor's Commission on Rebuilding, Recovery and Renewal, which was formed following Hurricane Katrina in 2005. Mr. Hood's business operations, risk management, and financial experience and civic involvement are valuable to the Board.



Donald M. James

Age:	63
Director since:	1999, Presiding Director since January 1, 2010
Board committees:	Compensation and Management Succession, Finance
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

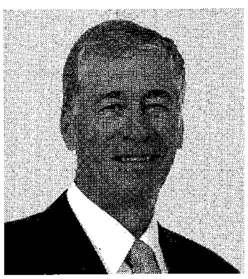
Age:	64
Director since:	2010
Board committees:	Governance, Nuclear/Operations
Principal occupation:	Associate Vice Chancellor of Research of the University of Texas System since January 2011 and Associate Director of the Energy Institute at The University of Texas at Austin since March 2010, university 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. He is a valuable addition to the Board due to his expertise in nuclear energy regulation and operations, technology, and safety.

William G. Smith, Jr.

Age:	58
Director since:	2006
Board committee:	Audit (*Chair*)
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

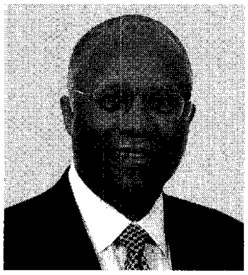
Director qualifications: Mr. Smith began his career at Capital City Bank in 1978, where he worked in a number of capacities before being elected President and Chief Executive Officer of Capital City Bank Group, Inc. in January 1989. He was elected Chairman of the Board of the Capital City Bank Group, 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. In addition, Mr. Smith qualifies as an audit committee financial expert.



Steven R. Specker

Age:	66
Director since:	2010
Board committees:	Governance, Nuclear/Operations
Other directorships:	Trilliant Incorporated

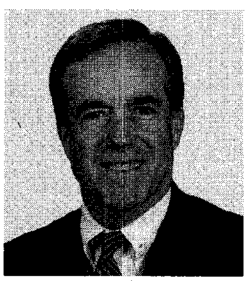
Director qualifications: Dr. Specker served as President and Chief Executive Officer of the Electric Power Research Institute (EPRI) from 2004 until his retirement in 2010. Prior to joining EPRI, Dr. Specker founded Specker Consulting, LLC, a private consulting firm, which provided operational and strategic 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.



Larry D. Thompson

Age:	66
Director since:	2010
Board committee:	Audit
Other directorships:	Cbeyond, Inc., Franklin, Templeton and Mutual Series Funds, The Washington Post Company

Director qualifications: From 2004 until his retirement in May 2011, Mr. Thompson served as Senior Vice President of Government Affairs, General Counsel, and Secretary of PepsiCo, Inc. (PepsiCo), one of the world's largest convenient food and beverage companies. In his role at PepsiCo, Mr. Thompson was responsible for PepsiCo's worldwide legal function, as well as its government affairs organization and the company's charitable foundation. Prior to joining PepsiCo in 2004, Mr. Thompson served as a Senior Fellow with The Brookings Institution. His government career also includes serving as Deputy Attorney General in the United States Department of Justice and leading the National Security Coordination Council. In 2002, President George W. Bush named Mr. Thompson to head the Department of Justice's Corporate Fraud Task Force. Mr. Thompson is a member of the Board of Cbeyond, Inc., where he serves as Chair of the Nominating and Corporate Governance Committee. He is also a Director or Trustee of various investment companies in the Franklin, Templeton and Mutual Series Funds. Mr. Thompson is a Director of The Washington Post Company, serving on the Compensation Committee. Mr. Thompson's government experience and corporate governance and legal expertise are valuable to the Board.



E. Jenner Wood III

Age:	60
Director since:	Nominee
Board committee:	n/a
Principal occupation:	Chairman, President, and Chief Executive Officer of the Atlanta/Georgia Division of SunTrust Bank since April 2010; Executive Vice President of SunTrust Banks, Inc. since July 2005, banking
Other directorships:	Oxford Industries, Inc., Crawford & Company, Georgia Power

Director qualifications: Since April 2010, Mr. Wood has served as Chairman, President, and Chief Executive Officer of the Atlanta/Georgia Division of SunTrust Bank where he is responsible for managing retail, commercial, and private wealth banking for the Greater Atlanta region and throughout the State of Georgia and as 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 35 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. Since 2002, he has served as a member of the Board of Georgia Power, the largest subsidiary of the Company. During his tenure on the Georgia Power Board, he has served as a member of the Compensation, Executive, and Finance Committees. Mr. Wood is a director of Oxford Industries, Inc. 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, 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 will be 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 2012. 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 2011 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 2011 Proxy Statement for the 2011 Annual Meeting of Stockholders. At that meeting, stockholders strongly approved the proposal, with more than 93% of the votes cast voting in favor of the proposal. Stockholders also 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) beginning on page 29, the Compensation Committee has structured the Company's executive compensation program based on the belief that executive compensation should:

- Be competitive with the companies in the Company's industry;
- 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 2011 and resulted in performance-based awards that exceeded target levels.

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 LLC.

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. The Executive Compensation section is found on pages 29 through 65 of this Proxy Statement.

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 2012 Annual Meeting of Stockholders pursuant to the compensation disclosure rules of the Securities and Exchange Commission, including the Compensation Discussion and Analysis, the 2011 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 — STOCKHOLDER PROPOSAL ON A COAL COMBUSTION BYPRODUCTS ENVIRONMENTAL REPORT

The Company has been advised that Green Century Capital Management, Inc., 114 State Street, Suite 200, Boston, Massachusetts 02109, holder of 120 shares of Common Stock, and Catholic Health East, 3805 West Chester Pike, Suite 100, Newtown Square, Pennsylvania 19073, holder of 154,040 shares of Common Stock, propose to submit the following resolution at the 2012 Annual Meeting of Stockholders.

"**Whereas**: Coal combustion waste (CCW or coal ash) is a by-product of burning coal that contains potentially high concentrations of arsenic, mercury, heavy metals and other toxins filtered out of smokestacks by pollution control equipment. CCW is often stored in landfills, impoundment ponds or abandoned mines. Over 130 million tons of CCW are generated each year in the U.S.

"Coal combustion comprised a significant portion (58%) of Southern Company's generation capacity in 2010.

"The toxins in CCW have been linked to cancer, organ failure, and other serious health problems. In October 2009, the U.S. Environmental Protection Agency (EPA) published a report finding that 'Pollutants in coal combustion wastewater are of particular concern because they can occur in large quantities (i.e., total pounds) and at high concentrations...in discharges and leachate to groundwater and surface waters.'

"The EPA has found evidence at over 60 sites in the U.S. that CCW has polluted ground and surface waters, including at least one site belonging to Southern Company. In some of these cases, companies have paid substantial fines and have suffered reputational consequences as a result of the contamination.

"Reports by the *New York Times* and others have drawn attention to CCW's impact on waterways, as a result of leaking CCW storage sites or direct discharge into surrounding rivers and streams.

"The Tennessee Valley Authority's (TVA) 1.1 billion gallon CCW spill in December 2008 that covered over 300 acres in eastern Tennessee with coal ash sludge highlights the serious environmental risks associated with CCW. TVA estimates a total cleanup cost of $1.2 billion. This figure does not include the legal claims that have arisen in the spill's aftermath.

"Southern Company operates 22 CCW storage facilities but does not disclose whether each of these ponds has liners, caps, groundwater monitoring, or leachate collection systems beyond compliance with current regulations. This information is critical for investors to understand the potential impact of our company's ash ponds on the environment and possible related risks.

"Our company also re-uses a significant portion of its CCW. Some forms of reusing dry CCW can pose public health and environmental risks in the dry form by leaching into water.

"**RESOLVED**: Shareholders request that the Board prepare a report on the company's efforts, above and beyond current compliance, to reduce environmental and health hazards associated with coal combustion waste contaminating water (including the implementation of caps, liners, groundwater monitoring, and/or leachate collection systems), and how those efforts may reduce legal, reputational and other risks to the company's finances and operations. This report should be available to shareholders by August 2012, be prepared at reasonable cost, and omit confidential information such as proprietary data or legal strategy."

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 4 FOR THE FOLLOWING REASONS:

The Company has already prepared a coal combustion byproducts report (CCB Report) addressing the issues raised in the proponents' proposal. The CCB Report has been posted on the Company's website since March 2010 and is updated periodically. The CCB Report includes relevant information on the Company's affiliates' operations related to coal combustion byproducts (CCBs), as well as the broad range of steps (including steps beyond current compliance) taken to ensure that the priorities of public safety and the security of the Company's affiliates' plants are met. The efforts identified in the CCB Report include procedures for safe handling, the beneficial use market, and technology research efforts. The Company's commitment to extensive environmental compliance procedures is a key element of the Company's management of legal, reputational, and other risks.

As detailed in the CCB Report, each of the Company's affiliates has an extensive system in place to meet or exceed all regulations governing CCB management and help ensure safe operation. In addition, a significant amount of CCBs from the Company's affiliates' coal-based power generation plants, including coal ash and gypsum, is recycled for safe and beneficial uses such as concrete production and road building. The beneficial use programs of the Company's affiliates have succeeded in reducing landfill obligations by more than 1.5 million tons annually and have many associated environmental benefits, including reductions in energy consumption, greenhouse gases, need for additional landfill space, and raw material consumption. The characteristics of CCBs enable beneficial uses and management of such CCBs to be undertaken safely. The concentration of metals in CCBs that occurs naturally in coal in trace amounts is much lower than the levels found in other substances that are required to be regulated as hazardous.

The CCB Report further discusses the Company's history of safe management of CCBs. While the Company's affiliates have focused recent efforts on the beneficial use of CCBs, they have safely managed the remaining CCBs at their respective plants for decades. Each of the Company's affiliates has a robust program in place to ensure the safety and integrity of dams and dikes at on-site surface impoundments. They are inspected at least every week by trained plant personnel and inspected at least every year by professional dam safety engineers.

Additionally, the CCB Report provides links to public disclosures regarding the Company's affiliates' plants that manage CCBs. In particular, a link to the extensive, detailed information about the Company's affiliates' management of CCBs that was provided to the U.S. Environmental Protection Agency (EPA) is included. The EPA issued information collection requests to facilities throughout the country that manage surface impoundments containing CCBs. The information provided to the EPA by the Company, along with the results of onsite inspections of the Company's affiliates' facilities, is available through a link to the EPA website (http://www.epa.gov/waste/nonhaz/industrial/special/fossil/surveys/index.htm), which link is also included in the CCB Report. The CCB Report also identifies the rules proposed by the EPA to regulate CCBs and provides a link to the Company's comments to these proposed rules.

The CCB Report provides details on the Company's research and development efforts with respect to CCB management, identifying initiatives to develop new and improved beneficial use of CCBs. As noted in the CCB Report, the Company has managed nearly $500 million in research and development over the past decade, including several projects to find new and innovative ways to beneficially use CCBs.

The Company also posts on its website a comprehensive report, the *Corporate Responsibility Report*, which was created in 2006 and is updated routinely as new information becomes available, relating to various topics. The

Corporate Responsibility Report includes a section relating to environmental matters and includes information on the management and beneficial use of CCBs.

Through the development of the reports discussed above, the Company has effectively addressed the proponents' proposal.

The Company-produced reports are available either through the Company's external website at www.southerncompany.com or by contacting Melissa K. Caen, Assistant Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308 and requesting a copy.

The vote needed to pass the proponents' resolution is the affirmative vote of a majority of the votes cast.

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

ITEM NO. 5 — STOCKHOLDER PROPOSAL ON A LOBBYING CONTRIBUTIONS AND EXPENDITURES REPORT

The Company has been advised that the Comptroller of the State of New York, as the sole Trustee of the New York State Common Retirement Fund, 633 Third Avenue 31st Floor, New York, New York 10017, holder of 2,838,582 shares of Common Stock, proposes to submit the following resolution at the 2012 Annual Meeting of Stockholders.

"**Whereas,** businesses have a recognized legal right to express opinions to legislators and regulators on public policy matters, it is important that our company's lobbying positions, as well as processes to influence public policy are transparent. Public opinion is skeptical of corporate influence on Congress and public policy and questionable lobbying activity may pose risks to our company's reputation when controversial positions are embraced. Hence, we believe full disclosure of Southern's policies, procedures and oversight mechanisms is warranted.

"**Resolved,** the stockholders of The Southern Company ('Southern') request the Board authorize the preparation of a report, updated annually, disclosing:

1. Company policy and procedures governing the lobbying of legislators and regulators, including that done on our company's behalf by trade associations. The disclosure should include both direct and indirect lobbying and grassroots lobbying communications.
2. A listing of payments (both direct and indirect, including payments to trade associations) used for direct lobbying as well as grassroots lobbying communications, including the amount of the payment and the recipient.
3. Membership in and payments to any tax-exempt organization that writes and endorses model legislation.
4. Description of the decision making process and oversight by the management and Board for
   a. direct and indirect lobbying contribution or expenditure; and
   b. payment for grassroots lobbying expenditure.

"For purposes of this proposal, a 'grassroots lobbying communication' is a communication directed to the general public that (a) refers to specific legislation, (b) reflects a view on the legislation and (c) encourages the recipient of the communication to take action with respect to the legislation.

"Both 'direct and indirect lobbying' and 'grassroots lobbying communications' include efforts at the local, state and federal levels.

"The report shall be presented to the Audit Committee of the Board or other relevant oversight committees of the Board and posted on the company's website.

"Supporting Statement

"As stockholders, we encourage transparency and accountability on the use of staff time and corporate funds to influence legislation and regulation both directly and indirectly as well as grassroots lobbying initiatives. We believe such disclosure is in the stockholder's best interests. Absent a system of accountability, company assets could be used for policy objectives contrary to a company's long-term interests posing risks to the company and stockholders.

"Southern spent approximately $26.67 million in 2009 and 2010 on direct federal lobbying activities, according to disclosure reports (*U.S. Senate Office of Public Records*). This figure may not include grassroots lobbying to directly influence legislation by mobilizing public support or opposition. Also, not all states require disclosure of lobbying expenditures to influence legislation or regulation.

"Such expenditures and contributions can potentially involve the company in controversies posing reputational risks.

"We encourage our Board to require comprehensive disclosure related to direct, indirect and grassroots lobbying."

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 5 FOR THE FOLLOWING REASONS:

The Board believes that the Company has a legitimate interest in participating in the legislative and regulatory process at the federal, state, and local levels of government when such participation is in the best interest of the Company and its stockholders. The Company is committed to transparency, accountability, and continuous improvement, including in the area of lobbying-related activities. The Company complies with all federal and state lobbying registration and disclosure requirements. Additionally, since the receipt of the proponent's resolution, the Company has undertaken to enhance its lobbying-related activities standards, procedures, and documents and also has enhanced its website disclosures to address concerns raised by the resolution. The Company believes that these enhancements, together with the Company's existing policies, practices, and procedures, satisfy the main purpose of the proponent's resolution.

Oversight

The Company's legislative and regulatory activities are overseen, and participation in coalitions, or the engagement of individuals and/or entities which perform any lobbying activities on behalf of the Company, are approved by the Company's Executive Vice President – External Affairs and the Company's Compliance Officer, and any federal lobbying engagement is reported at the time of approval to the Company's Vice President – Governmental Relations (Washington Office). For each subsidiary of the Company, these activities must be approved by the applicable subsidiary's senior External Affairs Officer and Compliance Officer if the engagement is through or also on behalf of such company. Additionally, management provides regular updates on lobbyists and lobbying activities to the Chief Executive Officer of the Company or of the applicable subsidiary of the Company involved, the Board of Directors of the Company, and the Company's management council.

Reporting

The Company provides its stockholders with useful information about its lobbying-related activities, including by posting its *Overview of Southern Company Policies and Practices for Lobbying-Related Activities*, as well as annually posting a listing of all trade associations to which it makes yearly payments of $50,000 or more, on its website at http://investor.southerncompany.com/political_contributions.cfm.

The Company and its subsidiaries fully comply with all federal and state lobbying registration and disclosure requirements, which include filing all required reports with Congress and with the applicable state ethics agencies. These reports on federal lobbying activities are readily available for public review on the websites of the U.S. House (www.house.gov) and the U.S. Senate (www.senate.gov) and provide information on activities associated with influencing legislation through communication with any member or employee of Congress or with any covered executive branch official. The federal reports also provide disclosure on expenditures for the applicable quarter, describe the specific pieces of legislation that were the topic of communications, and identify the individuals who lobbied on behalf of the Company or any of its subsidiaries. Subsidiaries of the Company and their registered lobbyists file similar publicly-available reports at the state level that are available for review from the applicable state ethics agencies.

Memberships

The Company is a member of a number of trade associations and industry groups at the local, state, and national level. All trade associations to which the Company makes yearly payments of $50,000 or more are disclosed on the Company's website. The Company believes that it is in the best interest of the Company and its stockholders to participate in trade associations specific to the Company's industry as trade associations allow the Company to collaborate with industry peers and, as a result, have a stronger impact than the Company might otherwise have individually. From time to time, some of these trade associations and industry groups communicate the position of its membership on public policy issues to government officials and the public. Although these trade association and industry groups are not primarily lobbying entities, a portion of the dues that the Company and other participants pay to such trade associations and industry groups may be part of the funds they use, in their sole discretion, to engage in lobbying activities. Because the Company does not direct how these funds are used and the Company may not agree with all positions such dues are used to support, disclosure of the Company's dues to each of these organizations could misrepresent the Company's position on legislative issues and would not provide stockholders with any meaningful information.

The Company is also a member of a number of tax-exempt organizations that, from time to time, write or endorse legislation (model or otherwise). This legislation may be unrelated to the Company and may be written or endorsed without the input of the Company. Because the Company may not agree with all positions taken by these tax-exempt organizations, disclosure of the Company's membership in such tax-exempt organizations could misrepresent the Company's position on legislative issues and would not provide stockholders with any meaningful information.

Conclusion

Based on the above, the Board believes that publicly-available information on the Company's lobbying activities, including information made available on the Company's website in response to the proponent's resolution, is understandable and, together with the oversight of the Company's legislative and regulatory activities by the Board and management discussed above, satisfy the main purpose of the proponent's resolution. The additional information requested by the proponent would be burdensome and would not materially alter the Company's current disclosure of its legislative and regulatory activities.

The vote needed to pass the proponent's resolution is the affirmative vote of a majority of the votes cast.

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

Audit Committee Report

The Audit Committee oversees the Company's financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for establishing and maintaining adequate internal controls over financial reporting, including disclosure controls and procedures, and for preparing the Company's consolidated financial statements. In fulfilling its oversight responsibilities, the Audit Committee reviewed the audited consolidated financial statements of the Company and its subsidiaries and management's report on the Company's internal control over financial reporting in the 2011 Annual Report to Stockholders attached hereto as Appendix B 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 2011.

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, 2011 and filed with the SEC. The Audit Committee also reappointed Deloitte & Touche as the Company's independent registered public accounting firm for 2012. Stockholders will be asked to ratify that selection at the Annual Meeting of Stockholders.

Members of the Audit Committee:

William G. Smith, Jr., Chair
Jon A. Boscia
Warren A. Hood, Jr.
Larry D. Thompson

PRINCIPAL INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FEES

The following represents the fees billed to the Company for the two most recent fiscal years by Deloitte & Touche — the Company's principal independent registered public accounting firm for 2011 and 2010.

	2011	2010
	(in thousands)	
Audit Fees (1)	$10,799	$10,670
Audit-Related Fees (2)	871	269
Tax Fees	0	0
All Other Fees	0	0
Total	$11,670	$10,939

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

(2) Includes non-statutory audit services in both 2011 and 2010.

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

This section describes the compensation program for the Company's Chief Executive Officer and Chief Financial Officer in 2011, 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
Charles D. McCrary	Executive Vice President of the Company and President and Chief Executive Officer of Alabama Power Company
Anthony J. Topazi	Executive Vice President and Chief Operating Officer

Executive Summary

Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2011.

	Salary ($)(1)	% of Total	Short-Term Performance Pay ($)(1)	% of Total	Long-Term Performance Pay ($)(1)	% of Total
T. A. Fanning	1,064,399	16	1,797,600	27	3,744,974	57
A. P. Beattie	552,614	24	667,680	28	1,140,613	48
W. P. Bowers	715,845	25	839,241	29	1,335,565	46
C. D. McCrary	752,219	24	933,091	30	1,403,427	46
A. J. Topazi	605,370	24	731,422	30	1,127,602	46

(1)Salary is the actual amount paid in 2011, Short-Term Performance Pay is the actual amount earned in 2011 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2011. 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 2011 are shown below:

Financial:	138% of Target
Operational:	186% of Target
EPS:	156% of Target

These levels of achievement resulted in actual payouts that exceeded targets. The Company's total shareholder return has been:

1-Year:	26.9%
3-Year:	13.4%
5-Year:	9.9%

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 companies in the Company's industry;
- 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 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 share units, 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 of an independent consultant, Pay Governance LLC, 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 and no income tax gross-ups, except on relocation-related benefits.
- "No-hedging" provision in the Company's inside 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 its independent compensation consultant, Pay Governance LLC. 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.

Review of Compensation and Benefits

In 2011, the Company conducted an extensive review of its compensation and benefit program. Numerous focus groups with employees at all levels were conducted and outside consultants were retained to review all aspects of the program.

The review was conducted with the support of, and input from, the Compensation Committee. The findings of the review confirmed that the Company's compensation and benefit program, including the appropriate payout levels under performance-based pay components, is competitive and consistent with industry peers. These findings were reviewed with the Compensation Committee.

Consideration of Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on the Company's executive compensation at the 2011 Annual Meeting of Stockholders. In light of the significant support of the stockholders (93% of votes cast voting in favor of the proposal) and the Company's strong performance in 2011, 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 and its stockholders.

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 approximately 26,000 employees of the Southern Company system. Stock options and performance shares are granted to approximately 3,000 employees of the Southern Company system. These programs engage employees, which ultimately is good not only for them, but also for the Company's subsidiaries' customers and the Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The executive compensation program has several components, each of which plays a different role. The following chart discusses the intended role of each material pay component, what it rewards, and why it is used. Following the chart is additional information that describes how 2011 pay decisions were made.

Pay Element	Intended Role and What the Element Rewards	Why the Element Is Used
Base Salary	Base salary is pay for competence in the executive role, with a focus on scope of responsibilities.	Market practice. Provides a threshold level of cash compensation for job performance.

Pay Element	Intended Role and What the Element Rewards	Why the Element Is Used
Annual Performance-Based Compensation: Performance Pay Program	The Performance Pay Program rewards achievement of business unit operational and financial goals and EPS.	Market practice. Focuses attention on achievement of short-term goals that ultimately work to fulfill the mission to customers and lead to increased stockholder value in the long term.
Long-Term Performance-Based Compensation: Stock Options	Stock options reward price increases in Common Stock over the market price on the date of grant, over a 10-year term.	Market practice. Performance-based compensation. Aligns recipients' interests with those of stockholders.
Long-Term Performance-Based Compensation: Performance Shares	Performance shares provide equity compensation dependent on the Company's three-year total shareholder return versus industry peers.	Market practice. Performance-based compensation. Aligns recipients' interests with stockholders' interests since payouts are dependent on the returns realized by stockholders versus those of industry peers.
Retirement Benefits	Executives participate in employee benefit plans available to all employees of the Southern Company system, including a 401(k) savings plan and the funded Southern Company Pension Plan (Pension Plan). The Southern Company Deferred Compensation Plan provides the opportunity to defer to future years up to 50% of base salary and all or part of performance-based non-equity compensation in either a prime interest rate or Common Stock account. The Supplemental Benefit Plan counts pay, including deferred salary, that is ineligible to be counted under the Pension Plan and the 401(k) plan due to Internal Revenue Service rules. The Supplemental Executive Retirement Plan counts annual performance-based pay above 15% of base salary for pension purposes.	Represents an important component of competitive market-based compensation in both the peer group and generally. Permitting compensation deferral is a cost-effective method of providing additional cash flow to the Company while enhancing the retirement savings of executives. The purpose of these supplemental plans is to eliminate the effect of tax limitations on the payment of retirement benefits.

Pay Element	Intended Role and What the Element Rewards	Why the Element Is Used
Perquisites and Other Personal Benefits	Personal financial planning maximizes the perceived value of the executive compensation program to executives and allows them to focus on operations. Limited personal use of corporate-owned aircraft associated with business travel. Relocation benefits cover the costs associated with geographic relocations at the request of the Company. Tax gross-ups are not provided on any perquisites except relocation-related benefits.	These limited perquisites represent an effective, low-cost means to retain key talent.
Severance Arrangements	Change-in-control plans provide severance pay, accelerated vesting, and payment of short- and long-term performance-based compensation upon a change in control of the Company coupled with involuntary termination not for cause or a voluntary termination for "Good Reason."	Market practice. Providing protections to executives upon a change in control minimizes disruption during a pending or anticipated change in control. Payment and vesting occur only upon the occurrence of both an actual change in control and loss of the executive's position.

MARKET DATA

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 LLC, the independent compensation consultant retained by the Compensation Committee. 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 $2 billion in revenues and up.

AGL Resources Inc.	Energy Future Holdings Corp.	PG&E Corporation
Allegheny Energy, Inc.	Entergy Corporation	Pinnacle West Capital Corporation
Alliant Energy Corporation	Exelon Corporation	PPL Corporation
Ameren Corporation	FirstEnergy Corp.	Progress Energy, Inc.
American Electric Power Company, Inc.	Hawaiian Electric Industries, Inc.	Public Service Enterprise Group Incorporated
Atmos Energy Corporation	Integrys Energy Group, Inc.	Puget Energy, Inc.
Calpine Corporation	LG&E and KU Energy LLC	Salt River Project
CenterPoint Energy, Inc.	MDU Resources Group, Inc.	SCANA Corporation
CMS Energy Corporation	Mirant Corporation	Sempra Energy
Consolidated Edison, Inc.	New York Power Authority	Spectra Energy Corp.
Constellation Energy Group, Inc.	NextEra Energy, Inc.	TECO Energy, Inc.
CPS Energy	Nicor Inc.	Tennessee Valley Authority
Dominion Resources, Inc.	Northeast Utilities	The Williams Companies, Inc.
DTE Energy Company	NRG Energy, Inc.	UGI Corporation
Duke Energy Corporation	NSTAR	Vectren Corporation
Dynegy Inc.	NV Energy, Inc.	Wisconsin Energy Corporation
Edison International	OGE Energy Corp.	Xcel Energy Inc.
El Paso Corporation	Pepco Holdings, Inc.	

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, the consultant size-adjusts the survey market data in order to fit it to the scope of the Company's business.

In using this market data, market is defined as the size-adjusted 50th percentile (median) of the survey data, with a focus on pay opportunities at target performance (rather than actual plan payouts). 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. 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 2011 compensation amounts. Total target compensation opportunities for senior management as a group are managed to be at the median of the market for companies of similar size in the electric utility industry. The total target compensation opportunity established in early 2011 for each named executive officer is shown in the following table.

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
T. A. Fanning	1,070,000	1,123,500	3,744,974	5,938,474
A. P. Beattie	556,400	417,300	1,140,613	2,114,313
W. P. Bowers	721,928	541,446	1,335,565	2,598,939
C. D. McCrary	758,611	568,958	1,403,427	2,730,996
A. J. Topazi	609,518	457,139	1,127,602	2,194,259

The salary levels shown above were not effective until March 2011. 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 2011.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $3.25 per option and performance shares at $35.97 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.

As discussed above, the Compensation Committee targets total compensation opportunities for senior management as a group at market. Therefore, some executives may be paid somewhat above and others somewhat below market. This practice allows for minor 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. The average total target compensation opportunities for the named executive officers for 2011 were at the median of the market data described above. 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, slight differences are not considered to be material and the compensation program is believed to be market-appropriate. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data.

In 2010, Pay Governance LLC, the Compensation Committee's independent consultant, analyzed the level of actual payouts for 2009 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 2011. That analysis was updated in 2011 by Pay Governance LLC for 2010 performance, and those findings were used in establishing goals for 2012.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2011 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2011. Base salary increases for each of the named executive officers were recommended in 2011 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 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 2011.

2011 Performance-Based Compensation

This section describes performance-based compensation for 2011.

<u>Achieving Operational and Financial Goals — The Guiding Principle for Performance-Based Compensation</u>

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 2011, 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 2011, 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).

2011 Annual Performance Pay Program

Program Design

The Performance Pay Program is the Company's annual performance-based compensation program. 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 Company (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.

For Messrs. Bowers and McCrary, the annual Performance Pay Program payout is calculated using the ROE for Georgia Power and Alabama Power, respectively. For Messrs. Fanning, Beattie, and Topazi, it is calculated using the aggregate ROE goal performance results for the traditional operating companies and the net income goal for Southern Power. The aggregate ROE goal is weighted 90% and the Southern Power net income goal is weighted 10% to determine the total corporate business unit financial goal performance.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial 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 earnings goal was established and of sufficient magnitude to warrant recognition. No adjustments to goal achievement were made in 2011 for financial goal results.

For Messrs. Bowers and McCrary, the payout is based on the operational goal results for Georgia Power and Alabama Power, respectively. For Messrs. Beattie, Fanning, and Topazi, it is based on the traditional operating company operational goal results (weighted 90%) and Southern Nuclear operational goal results (weighted 10%), collectively referred to as corporate operational goal results.

Mr. Bowers requested a 20% reduction in the safety goal achievement level for purposes of calculating his payout under the Performance Pay Program because there were two work-related fatalities in 2011 at Georgia Power. The reduction was approved by the Compensation Committee. This reduction is reflected in the total performance factor reported on page 39 of this CD&A. This reduction also was applicable to certain other employees of Georgia Power. The aggregate amount of the reduction in payouts was donated by Georgia Power to Electric Kids, Inc., a charitable organization that helps children of deceased or disabled employees of Georgia Power and Southern Company Services, Inc. who are or were based in Georgia.

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:

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.

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.

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.

Nuclear Plant Operation — This goal includes a measure for nuclear safety as rated by independent industry evaluators. It also includes nuclear plant reliability and a subjective assessment of progress on the construction and licensing of Georgia Power's two new nuclear units, Plant Vogtle Units 3 and 4. Nuclear reliability is a measurement of the percentage of time a nuclear plant is operating, except during planned outages.

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.

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.

The ranges of performance levels established for the primary operational goals are detailed below.

Level of Performance	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operation	Safety	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed target	Industry best	Significantly exceed targets	Greater than top 20th percentile and Company best	Significant improvement
Target	Top quartile overall	Historical Southern Company system average	Top quartile	Meet targets	Top 40th percentile	Improvement
Threshold	2nd quartile overall	Significantly below target	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. Collectively, customer satisfaction, reliability, availability, and nuclear plant operation are weighted 60% and safety and culture are weighted 20% each. 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 2011 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)
Maximum	2.65	14.0	150
Target	2.52	12.0	130
Threshold	2.39	10.0	110

For 2011, the Compensation Committee established a minimum EPS performance threshold that must be achieved. If EPS was less than $2.27 (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 committee responsibilities, see the committee descriptions beginning on page 8.

2011 Achievement

Each named executive officer had a target Performance Pay Program opportunity, based on his position, set by the Compensation Committee at the beginning of 2011. Targets are set as a percentage of base salary. Mr. Fanning's target was set at 105%. For Messrs. Beattie, Bowers, McCrary, and Topazi, the targets were set at 75% each. Actual payouts were determined by adding the payouts derived from EPS and applicable business unit operational and financial performance goal achievement for 2011 and dividing by three. EPS exceeded the minimum threshold established and therefore payouts were not affected. Actual 2011 goal achievement is shown in the following tables.

Operational Goal Results:

Corporate

Operating Company Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	197
Availability	200
Safety	197
Culture	147

Southern Nuclear Goal	Achievement Percentage
Nuclear Safety	178
Nuclear Reliability	145
Vogtle Units 3 and 4 Assessment	175

Alabama Power

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	182
Availability	200
Safety	134
Culture	160

Georgia Power

Goal	Achievement Percentage
Customer Satisfaction	167
Reliability	191
Availability	198
Safety	175
Culture	136

Overall, the levels of achievement shown above resulted in an operational goal performance factor for Corporate, Alabama Power, and Georgia Power of 186%, 177%, and 171%, respectively.

Financial Goal Results:

Goal	Result	Achievement Percentage
EPS	$2.57	156
Alabama Power ROE	13.19%	160
Georgia Power ROE	12.89%	145
Aggregate ROE	12.6%	131
Southern Power Net Income	$162 million	200

Overall, the levels of achievement shown above resulted in a business unit financial goal performance factor for Corporate, Alabama Power, and Georgia Power of 138%, 160%, and 145%, respectively.

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, as described above, 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	1,123,500	160	1,797,600
A. P. Beattie	417,300	160	667,680
W. P. Bowers	541,446	155	839,241
C. D. McCrary	568,958	164	933,091
A. J. Topazi	457,139	160	731,422

The total performance factor for Mr. Bowers reflects the reduction in the safety goal results as described above.

Long-Term Performance-Based Compensation

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 total shareholder return relative to industry peers, as well as stock price.

The following table shows the grant date fair value of the long-term performance-based awards in total and each component awarded in 2011.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
T. A. Fanning	1,498,000	2,246,974	3,744,974
A. P. Beattie	456,248	684,365	1,140,613
W. P. Bowers	534,225	801,340	1,335,565
C. D. McCrary	561,369	842,058	1,403,427
A. J. Topazi	451,042	676,560	1,127,602

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 2011, unvested options are forfeited if the named executive officer retires from the Company 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 2011 Annual Report attached as Appendix B to this Proxy Statement (Financial Statements). For 2011, the Black-Scholes value on the grant date was $3.25 per stock option.

Performance Shares

Performance shares are denominated in units, meaning no actual shares are issued at the grant date. A grant date fair value per unit was determined. For the grant made in 2011, that value per unit was $35.97. 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, 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 (as listed on page 33) 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	Exelon Corporation
American Electric Power Company, Inc.	FirstEnergy Corp.
CenterPoint Energy, Inc.	NextEra Energy, Inc.
Consolidated Edison, Inc.	Northeast Utilities
Constellation Energy Group, Inc.	PG&E Corporation
Dominion Resources, Inc.	Progress Energy, Inc.
DTE Energy Company	Public Service Enterprise Group Incorporated
Duke Energy Corporation	The AES Corporation
Edison International	Xcel Energy Inc.
Entergy Corporation	

The companies in the custom peer group are listed below.

American Electric Power Company, Inc.	PG&E Corporation
Consolidated Edison, Inc.	Progress Energy, Inc.
Duke Energy Corporation	Wisconsin Energy Corporation
Northeast Utilities	Xcel Energy Inc.
NSTAR	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2011 through 2013 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.

More information about stock options and performance shares is contained in the Grants of Plan-Based Awards table and the accompanying information.

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, performance dividends were paid on stock options granted prior to 2010 that were outstanding at the end of the four-year performance-measurement period that ended December 31, 2011, as reported in the Summary Compensation Table, and will be paid for one more uncompleted four-year performance-measurement period, 2009 through 2012. Because performance dividends granted prior to 2008 were paid on all stock options held at the end of each applicable performance-measurement period, absent the exercise of stock options, the number of stock options upon which performance dividends were paid increased over each four-year performance-measurement period due to annual stock option grants. During the transition period, the outstanding performance dividends are paid only on stock options granted prior to 2010. 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 will be earned at the end of 2012.

Performance dividends can range 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 will depend 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. The peer group was determined at the beginning of each four-year performance-measurement period. The peer group for performance dividends was set by the Compensation Committee at the beginning of the four-year performance-measurement period.

Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each company's common stock at the beginning of each of 16 quarters. In the final year of the performance-measurement period, the Company's ranking in the peer group is determined at the end of each quarter and the percentile ranking is 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 are 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.

2011 Payout

The peer group used to determine the 2011 payout for the 2008 through 2011 performance-measurement period consisted of utilities with revenues of $1.2 billion or more with regulated revenues of 60% or more. Those companies are listed below.

Allegheny Energy, Inc.	Entergy Corporation	Progress Energy, Inc.
Alliant Energy Corporation	Exelon Corporation	Puget Energy, Inc.
Ameren Corporation	Hawaiian Electric Company, Inc.	SCANA Corporation
American Electric Power Company, Inc.	NextEra Energy, Inc.	TECO Energy, Inc.
Avista Corporation	NiSource Inc.	UIL Holdings Corporation
CMS Energy Corporation	Northeast Utilities	Unisource Energy Corporation
Consolidated Edison, Inc.	NSTAR	Vectren Corporation
Dominion Resources, Inc.	NV Energy, Inc.	Westar Energy, Inc.
DPL Inc.	Pepco Holdings, Inc.	Wisconsin Energy Corporation
DTE Energy Corporation	PG&E Corporation	Xcel Energy Inc.
Duke Energy Corporation	Pinnacle West Capital Corporation	

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, 2011, based on performance during the 2008 through 2011 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 total shareholder return performance, as measured at the end of each quarter of the final year of the four-year performance-measurement period ending with 2011, was the 38^{th}, 41^{st}, 69^{th}, and 71^{st} percentile, respectively, resulting in a total payout of 112% of the target level (56.1% of the full year's Common Stock dividend), or $1.05. This amount was multiplied by each named executive officer's eligible outstanding stock options as of December 31, 2011 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.

Timing of Performance-Based Compensation

As discussed above, the 2011 annual Performance Pay Program goals and the total shareholder return goals applicable to performance shares were established at the February 2011 Compensation Committee meeting. Annual stock option grants also were made at that meeting. 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 2011 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

As mentioned above, certain post-employment compensation is provided to employees, including the named executive officers.

Retirement Benefits

Generally, all full-time employees of the Company 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. (These plans are the Supplemental Benefit Plan and the Supplemental Executive Retirement Plan that are described in the chart on page 32 of this CD&A.) 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

The Compensation Committee initially approved the change-in-control protection program in 1998 to provide certain compensatory protections to employees, including the named executive officers, upon a change in control and thereby allow them to negotiate aggressively with a prospective purchaser.

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.

In 2011, the Compensation Committee made changes to the program that were effective immediately. Notably, the following changes were made:

- Reduction of severance payment level from three times base salary plus target Performance Pay Program opportunity to two times that amount for all executive officers of the Company, including the named executive officers, except for the Chief Executive Officer; and
- Elimination of excise tax gross-up for all participants, including all of the named executive officers.

All individual agreements that were in place that provided for the higher severance benefit and excise tax gross-up were terminated.

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 2011, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites, except on 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. Messrs. McCrary and Topazi are age 60 or over.

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
C. D. McCrary	1.5 Times	3 Times
A. J. Topazi	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 and Beattie, have approximately five years from the date of their promotion to meet the increased 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 2011, the Compensation Committee approved a formula that represented a maximum annual performance-based compensation amount payable. For 2011 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 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 will reimburse 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 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, 2011 and in this Proxy Statement. The Board of Directors approved that recommendation.

Members of the Compensation Committee:
J. Neal Purcell, Chair
Henry A. Clark III
H. William Habermeyer, Jr.
Donald M. James

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2009, 2010, and 2011 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	2011	1,064,399	0	2,246,974	1,498,000	2,459,181	2,423,524	62,164	9,754,242
Chairman,	2010	809,892	0	782,054	521,378	1,951,986	1,902,932	50,909	6,019,151
President,	2009	690,250	0	0	457,744	1,086,911	927,301	38,432	3,200,638
and Chief									
Executive									
Officer									
Art P. Beattie	2011	552,614	0	684,365	456,248	772,343	1,523,479	83,471	4,072,520
Executive Vice	2010	385,211	53,500	125,040	83,366	635,909	1,135,073	530,681	2,948,780
President and Chief									
Financial Officer									
W. Paul Bowers	2011	715,845	0	801,340	534,225	1,232,850	1,317,429	42,052	4,643,741
President and Chief	2010	652,189	0	1,948,515	520,654	1,276,879	884,674	43,636	5,326,547
Executive Officer,	2009	614,870	0	0	491,085	967,334	931,232	44,410	3,048,931
Georgia Power									
Charles D. McCrary	2011	752,219	0	842,058	561,369	1,424,219	1,733,395	44,676	5,357,936
President and Chief	2010	704,520	0	779,192	519,461	1,534,615	919,066	42,285	4,499,139
Executive Officer,	2009	687,713	0	0	431,932	1,350,171	1,195,625	48,375	3,713,816
Alabama Power									
A. J. Topazi	2011	605,370	0	676,560	451,042	969,009	1,907,845	217,375	4,827,201
Executive Vice	2010	476,622	228,594	261,980	174,669	807,490	984,283	196,982	3,130,620
President and Chief	2009	407,433	0	0	178,697	542,370	678,982	29,437	1,836,919
Operating Officer									

Column (a)

Mr. Beattie was not an executive officer of the Company prior to 2010.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2011. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2011. 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, 2013. 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 2011 to Messrs. Fanning, Beattie, Bowers, McCrary, and Topazi, assuming that the highest level of performance is achieved, is $4,493,948, $1,368,730, $1,602,680, $1,684,116, and $1,353,120, respectively (200% of the amount shown in the table). See Note 8 to the Financial Statements for a discussion of the assumptions used in calculating these amounts.

As described in detail in the CD&A, in 2010, the first awards of performance shares were made and no further awards of performance dividends were made. In 2009, stock options were awarded (as shown in column (f)) with associated performance dividends, as described in the CD&A. The grant date value of performance dividends was reported in the CD&A and the threshold, target, and maximum payouts of performance dividends based on certain assumptions were reported in the Grants of Plan-Based Awards table. However, because of SEC disclosure requirements, no grant date value for performance dividend awards was disclosed in the Summary Compensation Table in the year granted. Instead, the actual cash payouts in the applicable year with respect to all outstanding performance dividends were reported as Non-Equity Incentive Plan Compensation in column (g). The grant date value for performance dividends, as reported in the CD&A for 2009, is as follows:

T. A. Fanning	$798,508
A. P. Beattie	$128,618
W. P. Bowers	$856,671
C. D. McCrary	$753,481
A. J. Topazi	$311,727

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 under the Performance Dividend Program. The amount reported for annual performance-based compensation is for the one-year performance period ended December 31, 2011. The amount reported for performance dividends is the amount earned at the end of the four-year performance-measurement period of January 1, 2008 through December 31, 2011. These awards were granted by the Compensation Committee in 2008 and were paid on stock options granted prior to 2010 that were outstanding at the end of 2011. 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 second 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	1,797,600	661,581	2,459,181
A. P. Beattie	667,680	104,663	772,343
W. P. Bowers	839,241	393,609	1,232,850
C. D. McCrary	933,091	491,128	1,424,219
A. J. Topazi	731,422	237,587	969,009

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, 2009, 2010, and 2011. 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, 2011, 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, 2010 and December 31, 2011 follow:

- Discount rate for the Pension Plan was decreased to 5.0% as of December 31, 2011 from 5.55% as of December 31, 2010, and

- Discount rate for the supplemental pension plans was decreased to 4.65% as of December 31, 2011 from 5.05% as of December 31, 2010.

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; the employer contributions in 2011 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 2011 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 2011 are itemized below.

	Perquisites ($)	**Tax Reimbursements ($)**	**ESP ($)**	**SBP ($)**	**Total ($)**
T. A. Fanning	7,880	0	12,495	41,789	62,164
A. P. Beattie	56,600	462	10,721	15,688	83,471
W. P. Bowers	5,850	0	12,189	24,013	42,052
C. D. McCrary	8,146	0	10,662	25,868	44,676
A. J. Topazi	137,397	49,104	12,495	18,379	217,375

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. Messrs. Beattie and Topazi received relocation-related benefits in 2011 of $52,000 and $131,790, respectively. Mr. Beattie relocated from Birmingham, Alabama to Atlanta, Georgia in 2010. Mr. Beattie's relocation assistance provided in 2011 was for the shipment of household goods and incidental expenses related to his move. Mr. Topazi's relocation assistance includes the incremental cost paid or incurred by the Company for his relocation from Gulfport, Mississippi to Birmingham, Alabama, including loss on home sale of his primary residence in Gulfport, home sale and home repurchase assistance (closing costs), shipment of household goods, temporary housing costs during the move, and a lump sum relocation allowance. Under the relocation policy applicable to all employees, any loss on home sale is determined based on the purchase price paid by Mr. Topazi for his primary residence. Also, as provided in the policy, tax assistance was provided on the taxable relocation benefits, including the reimbursement for loss on home sale. If Mr. Topazi terminates within two years of his relocation, the amount provided for loss on home sale, including tax assistance, 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.

Effective in 2009, for executive officers of the Company, including the named executive officers, tax reimbursements are no longer made on perquisites, except on relocation-related benefits. The tax reimbursement shown is the amount paid on relocation benefits as described above.

GRANTS OF PLAN-BASED AWARDS IN 2011

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2011 by the Compensation Committee.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Option; Awards Number of Securities Underlying Options	Exercise Or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	(#) (i)	($/Sh) (j)	($) (k)
T. A. Fanning	2/14/2011	11,235	1,123,500	2,247,000						
	2/14/2011				625	62,468	124,936			2,246,974
	2/14/2011							460,923	37.97	1,498,000
A. P. Beattie	2/14/2011	4,173	417,300	834,600						
	2/14/2011				190	19,026	38,052			684,365
	2/14/2011							140,384	37.97	456,248
W. P. Bowers	2/14/2011	5,414	541,446	1,082,892						
	2/14/2011				223	22,278	44,556			801,340
	2/14/2011							164,377	37.97	534,225
C. D. McCrary	2/14/2011	5,690	568,958	1,137,916						
	2/14/2011				234	23,410	46,820			842,058
	2/14/2011							172,729	37.97	561,369
A. J. Topazi	2/14/2011	4,571	457,139	914,278						
	2/14/2011				188	18,809	37,618			676,560
	2/14/2011							138,782	37.97	451,042

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

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2011 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 2011, 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 2011 through 2013 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2011, as described in the CD&A, and column (j) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2011. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model. The assumptions used in calculating these amounts are discussed in Note 8 to the Financial Statements.

OUTSTANDING EQUITY AWARDS AT 2011 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, 2011.

	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	80,843	0	32.70	02/18/2015				
	95,392	0	33.81	02/20/2016				
	99,382	0	36.42	02/19/2017				
	100,158	0	35.78	02/18/2018				
	169,535	84,767	31.39	02/16/2019				
	77,934	155,868	31.17	02/15/2020				
	0	460,923	37.97	02/14/2021				
							885	40,967
A. P. Beattie	21,558	0	32.70	02/18/2015				
	20,138	0	33.81	02/20/2016				
	22,550	0	36.42	02/19/2017				
	21,779	0	35.78	02/18/2018				
	0	13,654	31.39	02/16/2019				
	12,462	24,922	31.17	02/15/2020				
	0	140,384	37.97	02/14/2021				
							232	10,739
W. P. Bowers	60,576	0	32.70	02/18/2015				
	67,517	0	33.81	02/20/2016				
	70,680	0	36.42	02/19/2017				
	85,151	0	35.78	02/18/2018				
	0	90,942	31.39	02/16/2019				
	77,826	155,651	31.17	02/15/2020				
	0	164,377	37.97	02/14/2021				
							482	22,312
					34,744	1,608,300		
C. D. McCrary	86,454	0	32.70	02/18/2015				
	99,178	0	33.81	02/20/2016				
	102,333	0	36.42	02/19/2017				
	99,789	0	35.78	02/18/2018				
	0	79,987	31.39	02/16/2019				
	0	155,294	31.17	02/15/2020				
	0	172,729	37.97	02/14/2021				
							493	22,821
A. J. Topazi	40,939	0	33.81	02/20/2016				
	43,062	0	36.42	02/19/2017				
	42,996	0	35.78	02/18/2018				
	66,184	33,092	31.39	02/16/2019				
	0	52,218	31.17	02/15/2020				
	0	138,782	37.97	02/14/2021				
							275	12,730

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 2008 with expiration dates from 2015 through 2018 were fully vested as of December 31, 2011. The options granted in 2009, 2010, and 2011 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2009	February 16, 2019	February 16, 2012
2010	February 15, 2020	February 15, 2013
2011	February 14, 2021	February 14, 2014

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)

Column (f) reflects the number of restricted stock units, including the deemed reinvestment of dividends, held as of December 31, 2011. The value in column (g) is based on the Common Stock closing price on December 30, 2011 ($46.29). The restricted stock units vest on July 27, 2013.

Columns (h) and (i)

Column (h) reflects the threshold number of performance shares that can be earned at the end of the three-year performance periods (December 31, 2012 and December 31, 2013) that were granted in 2010 and 2011. The value in column (i) is derived by multiplying the number of shares in column (h) by the Common Stock closing price on December 30, 2011 ($46.29). See further discussion of performance shares in the CD&A.

OPTION EXERCISES AND STOCK VESTED IN 2011

	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	0	0	0	0
A. P. Beattie	27,307	269,247	0	0
W. P. Bowers	181,883	1,736,369	0	0
C. D. McCrary	237,623	2,034,217	0	0
A. J. Topazi	63,914	657,980	0	0

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2011 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.

No stock awards (performance shares and restricted stock units) vested in 2011.

PENSION BENEFITS AT 2011 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	30	858,649	0
	Supplemental Benefit Plan (Pension-Related)	30	4,617,286	0
	Supplemental Executive Retirement Plan	30	2,881,940	0
A. P. Beattie	Pension Plan	34.92	1,132,939	0
	Supplemental Benefit Plan (Pension-Related)	34.92	1,904,037	0
	Supplemental Executive Retirement Plan	34.92	1,371,769	0
W. P. Bowers	Pension Plan	31.67	918,112	0
	Supplemental Benefit Plan (Pension-Related)	31.67	3,236,973	0
	Supplemental Executive Retirement Plan	31.67	1,437,515	0
C. D. McCrary	Pension Plan	37	1,372,089	0
	Supplemental Benefit Plan (Pension-Related)	37	6,032,274	0
	Supplemental Executive Retirement Plan	37	1,963,422	0
A. J. Topazi	Pension Plan	38.5	1,503,816	0
	Supplemental Benefit Plan (Pension-Related)	38.5	3,477,293	0
	Supplemental Executive Retirement Plan	38.5	1,992,224	0

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 2011 was $245,000.

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 paid or deferred during 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. All of the named executive officers are retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. All of the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed, 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 the extra service crediting, the normal 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 an 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 6%. 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 also is 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 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 — 5.00% Pension Plan and 4.65% supplemental plans as of December 31, 2011,
- 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 — 4.00% discount rate for single sum calculation and 4.75% 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 2011 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	195,199	41,789	196,763	0	1,902,063
A. P. Beattie	0	15,688	34,755	0	426,516
W. P. Bowers	267,240	24,013	482,237	0	3,190,836
C. D. McCrary	0	25,868	186,807	0	1,519,627
A. J. Topazi	0	18,379	59,937	0	848,821

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 2011, the rate of return in the Stock Equivalent Account was 26.9%, which was the Company's total shareholder return for 2011.

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 2011 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 2011. 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 2011 were the amounts paid for performance under the annual Performance Pay Program and the Performance Dividend Program that were earned as of December 31, 2010 but not payable until the first quarter of 2011. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2011 but not payable until early 2012. 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 2011 and previously reported ($)	Employer Contributions under the SBP prior to 2011 and previously reported ($)	Total ($)
T. A. Fanning	1,054,504	237,224	1,291,728
A. P. Beattie	34,781	7,151	41,932
W. P. Bowers	1,269,490	68,530	1,338,020
C. D. McCrary	489,924	295,716	785,640
A. J. Topazi	0	0	0

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, 2011 and assumes that the price of Common Stock is the closing market price on December 30, 2011.

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 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.
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.

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
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, 2011.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2011 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 since all were retirement-eligible on December 31, 2011 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. 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.

		Retirement ($)	Resignation or Involuntary Termination	Death (payments to a spouse) ($)
T. A. Fanning	Pension	6,170	treated as retiring	4,400
	SBP-P	601,741	treated as retiring	601,741
	SERP	375,584	treated as retiring	375,584
A. P. Beattie	Pension	8,285	treated as retiring	5,107
	SBP-P	240,279	treated as retiring	240,279
	SERP	173,110	treated as retiring	173,110
W. P. Bowers	Pension	6,611	treated as retiring	4,648
	SBP-P	421,583	treated as retiring	421,583
	SERP	187,222	treated as retiring	187,222
C. D. McCrary	Pension	10,034	treated as retiring	5,486
	SBP-P	719,615	treated as retiring	719,615
	SERP	234,225	treated as retiring	234,225
A. J. Topazi	Pension	10,921	treated as retiring	5,623
	SBP-P	399,751	treated as retiring	399,751
	SERP	229,027	treated as retiring	229,027

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. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2011 following a change-in-control 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	6,017,409	3,755,845	9,773,254
A. P. Beattie	2,402,787	1,731,095	4,133,882
W. P. Bowers	4,215,826	1,872,216	6,088,042
C. D. McCrary	7,196,145	2,342,246	9,538,391
A. J. Topazi	3,997,507	2,290,266	6,287,773

The pension benefit amounts in the tables above were calculated as of December 31, 2011 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 3.77% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2011 is the greater of target or actual performance. Because actual payouts for 2011 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, 2011, 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 event, performance dividends are payable at the greater of target performance or actual performance. For the 2008 through 2011 performance-measurement period, actual performance exceeded target-level performance.

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 Equity Awards would be paid to the named executive officers. For stock options, that value is the excess of the exercise price and the closing price of Common Stock on December 30, 2011, and for performance shares and restricted stock units, it is the closing price on December 30, 2011. 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	701,558	88,424	0	1,324,802	88,424	0	19,574,922
A. P. Beattie	178,960	23,176	0	277,447	23,176	0	4,005,264
W. P. Bowers	410,970	48,198	34,744	772,720	48,198	34,744	13,350,598
C. D. McCrary	408,010	49,271	0	795,764	49,271	0	11,729,172
A. J. Topazi	224,092	27,504	0	417,273	27,504	0	6,084,404

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 are retired or retirement-eligible. Healthcare benefits are provided to retirees and there is no incremental payment associated with the termination or change-in-control events.

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.

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 two times the base salary and target payout under the annual Performance Pay Program.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2011 in connection with a change in control.

	Severance Amount ($)
T. A. Fanning	6,586,500
A. P. Beattie	1,953,400
W. P. Bowers	2,532,747
C. D. McCrary	2,661,137
A. J. Topazi	2,139,314

COMPENSATION RISK ASSESSMENT

Southern Company reviewed its compensation policies and practices, including those of the Company, 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 2011, 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, except for an inadvertent late filing of a Form 4 by Mr. W. Ron Hinson, Comptroller and Chief Accounting Officer.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Mr. Donald M. James is the Chief Executive Officer of Vulcan Materials Company. During 2011, subsidiaries of the Company purchased approximately $8,954,615 of goods and services from Vulcan Materials Company and its affiliates, primarily related to an on-going construction project.

Mr. E. Jenner Wood III, a Director nominee of the Company, is Chairman, President, and Chief Executive Officer of the Atlanta/Georgia Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc. During 2011, subsidiaries of the Company made payments of approximately $434,233 to certain subsidiaries of SunTrust Banks, Inc., substantially related to an equipment lease.

During 2011, 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. The Company and its subsidiaries intend to maintain normal banking relations with SunTrust Banks, Inc. and its subsidiaries in the future.

The Company does not have a written policy pertaining solely to the approval or ratification of "related party transactions." The Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/ services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

APPENDIX A

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 B

SOUTHERN COMPANY

2011 ANNUAL REPORT

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SOUTHERN COMPANY COMMON STOCK AND DIVIDEND INFORMATION

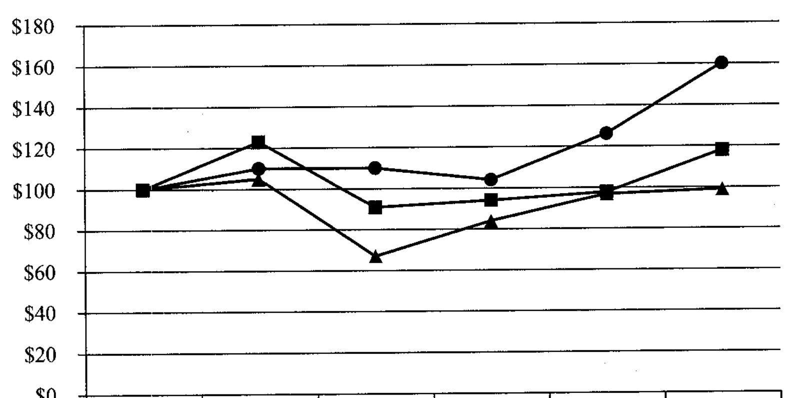
The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low	Dividend
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
2010			
First Quarter	$33.73	$30.85	$0.4375
Second Quarter	35.45	32.04	0.4550
Third Quarter	37.73	33.00	0.4550
Fourth Quarter	38.62	37.10	0.4550

On March 26, 2012, Southern Company had 148,524 registered stockholders.

FIVE-YEAR CUMULATIVE PERFORMANCE GRAPH

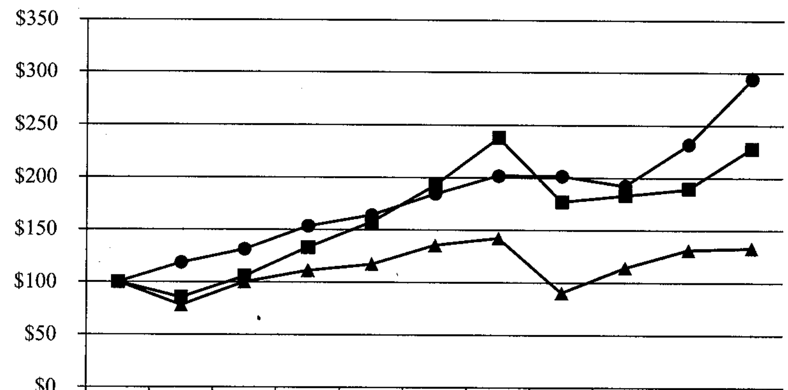
This performance graph compares the cumulative total shareholder return on the Company's common stock (SO) with the Standard & Poor's Electric Utility Index (S5ELUT) and the Standard & Poor's 500 index (SPX) for the past five years. The graph assumes that $100 was invested on December 31, 2006 in the 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.



	2006	2007	2008	2009	2010	2011
SPX	100	105	67	84	97	99
S5ELUT	100	123	91	94	98	118
SO	100	110	110	104	126	160

TEN-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 10 years. The graph assumes that $100 was invested on December 31, 2001 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 10-year historical period may not be indicative of future performance.



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
SPX	100	78	100	111	117	135	142	90	114	131	133
S5ELUT	100	85	105	133	157	193	238	177	183	189	228
SO	100	118	131	153	164	184	202	201	192	231	294

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Company and Subsidiary Companies 2011 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, 2011.

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, 2011. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

Thomas A. Fanning

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

Art P. Beattie

Art P. Beattie
Executive Vice President and Chief Financial Officer

February 24, 2012

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, 2011 and 2010, 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, 2011. We also have audited the Company's internal control over financial reporting as of December 31, 2011, 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 B-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 B-38 to B-100) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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 24, 2012

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, 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 Company 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) 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 maximize shareholder value while providing cost-effective energy to more than four million customers, Southern Company 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 the satisfaction of its customers. 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 2011 Peak Season EFOR of 1.28%, excluding the impact of tornadoes in April 2011, was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2011 was better than the target for these reliability measures.

Southern Company's 2011 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2011 Target Performance	2011 Actual Performance
System Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season System EFOR - fossil/hydro	4.80% or less	1.28%
Basic EPS	$2.48 – $2.56	$2.57

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2011 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 $2.20 billion in 2011, an increase of $228 million 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 and $1.64 billion in 2009.

Basic EPS was $2.57 in 2011, $2.37 in 2010, and $2.07 in 2009. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.55 in 2011, $2.36 in 2010, and $2.06 in 2009. EPS for 2011 was negatively impacted by $0.08 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 $1.8725 in 2011, $1.8025 in 2010, and $1.7325 in 2009. In January 2012, Southern Company declared a quarterly dividend of 47.25 cents per share. This is the 257th 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% of net income. For 2011, the actual payout ratio was 73%.

RESULTS OF OPERATIONS

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	
	2011	2011	2010
		(in millions)	
Electric operating revenues	$ 17,587	$ 213	$ 1,732
Fuel	6,262	(437)	747
Purchased power	608	45	89
Other operations and maintenance	3,842	(63)	505
Depreciation and amortization	1,700	205	19
Taxes other than income taxes	899	32	51
Total electric operating expenses	13,311	(218)	1,411
Operating income	4,276	431	321
Other income (expense), net	99	(59)	(40)
Interest expense, net of amounts capitalized	803	(30)	(1)
Income taxes	1,293	179	126
Net income	2,279	223	156
Dividends on preferred and preference stock of subsidiaries	65	-	-
Net income after dividends on preferred and preference stock of subsidiaries	$ 2,214	$ 223	$ 156

Electric Operating Revenues

Details of electric operating revenues were as follows:

	Amount	
	2011	2010
	(in millions)	
Retail – prior year	$ 14,791	$ 13,307
Estimated change in –		
Rates and pricing	793	384
Sales growth (decline)	38	32
Weather	(279)	439
Fuel and other cost recovery	(272)	629
Retail – current year	15,071	14,791
Wholesale revenues	1,905	1,994
Other electric operating revenues	611	589
Electric operating revenues	$ 17,587	$ 17,374
Percent change	1.2%	11.1%

Retail revenues increased $280 million and $1.5 billion in 2011 and 2010, respectively. The significant factors driving these changes 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 includes 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 effective January 1, 2011. See "Other Income (Expense), Net" 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 certificated new plant environmental (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. The 2010 increase in rates and pricing was primarily due to revenues associated with increases in rates under Alabama Power's stabilization and equalization plan (Rate RSE) and Rate CNP Environmental and the recovery of environmental costs at Gulf Power. 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 fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, 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 2011, wholesale revenues decreased $89 million 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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010.

In 2010, wholesale revenues increased $192 million primarily due to higher capacity and energy revenues under existing PPAs and new PPAs at Southern Power, as well as increased energy sales that were not covered by PPAs at Southern Power due to more favorable weather. This increase was partially offset by 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.

Revenues associated with PPAs and opportunity sales were as follows:

	2011	2010	2009
		(in millions)	
Other power sales –			
Capacity and other	**$ 767**	$ 684	$ 575
Energy	**1,035**	1,034	735
Total	**$ 1,802**	$ 1,718	$ 1,310

Kilowatt-hour (KWH) sales under unit power sales contracts decreased 69.6% and 55.0% in 2011 and 2010, respectively. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010, which resulted in a decrease in capacity and energy revenues. In addition, fluctuations in oil and natural gas prices, which are the primary fuel sources 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:

	2011	2010	2009
		(in millions)	
Unit power sales –			
Capacity	**$ 53**	$ 136	$ 225
Energy	**50**	140	267
Total	**$ 103**	$ 276	$ 492

Other Electric Revenues

Other electric revenues increased $22 million and $56 million in 2011 and 2010, respectively. Other electric revenues increased in 2011 primarily as a result of an increase in transmission revenues at Georgia Power. The 2010 increase in other electric revenues was primarily the result of a $38 million increase in transmission revenues, a $4 million increase in rents from electric property, a $4 million increase in outdoor lighting revenues, and a $4 million increase in late fees.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2011 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2011	**2011**	2010	**2011**	2010
	(in billions)				
Residential	**53.3**	**(7.7)%**	11.8%	**0.0%**	0.2%
Commercial	**53.9**	**(2.9)**	3.7	**(0.3)**	(0.6)
Industrial	**51.6**	**3.2**	7.7	**3.3**	7.1
Other	**0.9**	**(0.8)**	(1.0)	**(0.7)**	(1.5)
Total retail	**159.7**	**(2.7)**	7.6	**1.0%**	2.0%
Wholesale	**30.3**	**(6.8)**	(2.8)		
Total energy sales	**190.0**	**(3.4)%**	5.7%		

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 4.5 billion KWHs in 2011. 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. Retail energy sales increased 11.6 billion KWHs in 2010 primarily as a result of colder weather in the first and fourth quarters 2010 and warmer weather in the second and third quarters 2010 when compared to the corresponding periods in 2009, increased industrial KWH sales, and customer growth of 0.3%. Increased demand in the primary metals, chemicals, and transportations sectors was the main contributor to the increase in industrial KWH sales.

Wholesale energy sales decreased 2.2 billion KWHs in 2011 and 0.9 billion KWHs in 2010. 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. The decrease in wholesale energy sales in 2010 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 existing PPAs and new PPAs at Southern Power, as well as sales that were not covered by PPAs at Southern Power primarily due to more favorable weather in 2010 compared to 2009. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Rate CNP" herein for additional information regarding the termination of certain unit power sales contracts in 2010.

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 electricity generated and purchased by the electric utilities were as follows:

	2011	2010	2009
Total generation *(billions of KWHs)*	**186**	196	187
Total purchased power *(billions of KWHs)*	**12**	10	8
Sources of generation *(percent)* –			
Coal	**52**	58	57
Nuclear	**16**	15	16
Gas	**30**	25	23
Hydro	**2**	2	4
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**4.02**	3.93	3.70
Nuclear	**0.72**	0.63	0.55
Gas	**3.89**	4.27	4.58
Average cost of fuel, generated *(cents per net KWH)*	**3.43**	3.50	3.38
Average cost of purchased power *(cents per net KWH)* *	**6.32**	6.98	6.37

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

In 2011, fuel and purchased power expenses were $6.9 billion, a decrease of $392 million, or 5.4%, compared to 2010 costs. This decrease was primarily the result of a $186 million net decrease in the amount of total KWHs generated and purchased and a $206 million decrease in the average cost per KWH generated and purchased. The net decrease in total amount of KWHs generated and purchased was mainly the result of lower demand primarily due to closer to normal weather in 2011 compared to 2010. The decrease in the average cost per KWH generated and purchased was primarily the result of an 8.9% decrease in the average cost per gas KWH generated and a 9.5% decrease in the average cost per KWH purchased.

In 2010, fuel and purchased power expenses were $7.3 billion, an increase of $836 million, or 13.0%, compared to 2009 costs. This increase was primarily the result of a $538 million increase in the amount of total KWHs generated and purchased due primarily to increased customer demand. Also contributing to this increase was a $298 million increase in the average cost per KWH generated and purchased due primarily to a 3.6% increase in the cost per KWH generated and a 9.6% increase in the cost per KWH purchased.

From an overall global market perspective, coal prices continued to increase in 2011 from the levels experienced in 2010, but remained lower than the unprecedented high levels of 2008. The slowly recovering U.S. economy and global demand from coal importing countries drove the higher prices in 2011, with concerns over regulatory actions, such as permitting issues, and their negative impact on production also contributing upward pressure. Domestic natural gas prices continued to be depressed by robust supplies, including production from shale gas, as well as lower demand. The combination of higher coal prices and lower natural gas prices contributed to increased use of natural gas-fueled generating units in 2011. In early 2011, uranium prices continued the steady increase started during the second half of 2010. In March 2011, uranium prices fell sharply from the highs earlier in the year. After some price volatility in the second quarter 2011, the price leveled and remained relatively constant for the remainder of 2011. At year end, uranium prices remained well below the highs set during 2007. Worldwide uranium production levels increased in 2011; however, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the traditional operating companies' fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. Likewise, Southern Power's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $3.8 billion and $3.9 billion, decreasing $63 million and increasing $505 million in 2011 and 2010, respectively. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants increased $2 million and $277 million in 2011 and 2010, respectively. 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 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. This increase was largely offset by a decrease in nuclear outage expense at Alabama Power, primarily related to a change to the nuclear maintenance outage accounting process associated with the routine refueling activities, as approved by the Alabama Public Service Commission (PSC) in August 2010. 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. Other production expenses increased in 2010 mainly due to a $178 million increase in outage and maintenance costs and an $86 million increase in commodity and labor costs, reflecting a return to more normal spending levels when compared to 2009. Also contributing to this increase was an $18 million increase in maintenance costs related to additional equipment placed in service. Partially offsetting the 2010 increase was a $5 million loss recognized in 2009 on the transfer of Southern Power's Plant Desoto.

Transmission and distribution expenses decreased $80 million in 2011 and increased $143 million in 2010. 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 2011 primarily due to reductions in spending related to vegetation management and a reduction in accruals to the natural disaster reserve (NDR) at Alabama Power. Transmission and distribution expenses increased in 2010 primarily due to increased spending related to vegetation management and other maintenance costs, reflecting a return to more normal spending levels, as well as an additional accrual to Alabama Power's NDR. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information.

Customer sales and service expenses increased $33 million and $18 million in 2011 and 2010, respectively. Customer 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. Customer sales and service expenses increased in 2010 primarily as a result of an $8 million increase in sales expenses, a $13 million increase in customer service expense, a $10 million increase in records and collection expense, and a $3 million increase in uncollectible accounts expense. Partially offsetting this increase was a $7 million decrease in meter reading expenses and a $9 million decrease in other energy services.

Administrative and general expenses decreased $18 million in 2011 and increased $67 million in 2010. 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. Administrative and general expenses increased in 2010 primarily as a result of cost containment activities in 2009 which were taken to offset the effects of the recessionary economy.

Depreciation and Amortization

Depreciation and amortization increased $205 million in 2011 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 1 to the financial statements under "Depreciation and Amortization" and 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.

Depreciation and amortization increased $19 million in 2010 primarily as the result of additional depreciation on plant in service related to environmental, transmission, and distribution projects, as well as additional depreciation at Southern Power. This increase was largely offset by a $133 million increase in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $32 million in 2011 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. Taxes other than income taxes increased $51 million in 2010 primarily due to increases in municipal franchise fees at Georgia Power, increases in state and municipal public utility license tax bases at Alabama Power, increases in gross receipts and franchise fees at Gulf Power, increases in ad valorem taxes, and increases in payroll taxes. Increases in franchise fees are associated with increases in revenues from energy sales.

Other Income (Expense), Net

Other income (expense), net decreased $59 million in 2011 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. Also contributing to the decrease was reduced AFUDC equity at Alabama Power due to the completion of construction projects related to environmental mandates and a $20 million loss at Southern Power related to a make-whole premium in connection with the early redemption of senior notes. The 2011 decrease was partially offset by construction work in progress related to Mississippi Power's Kemper County integrated coal gasification combined cycle (Kemper IGCC) which began construction in June 2010. Other income (expense), net decreased $40 million in 2010 primarily due to a decrease in AFUDC equity, mainly due to the completion of environmental projects at Alabama Power and Gulf Power, and a $13 million profit recognized in 2009 at Southern Power related to a construction contract with the Orlando Utilities Commission. The 2010 decrease was partially offset by increases in AFUDC equity related to the increase in construction of three new combined cycle units and Plant Vogtle Units 3 and 4 at Georgia Power. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Total interest charges and other financing costs decreased $30 million in 2011 primarily due to a reduction of $23 million in interest expense at Georgia Power related to the settlement of litigation with the Georgia Department of Revenue (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.

Total interest charges and other financing costs decreased $1 million in 2010 primarily due to an $18 million decrease related to lower average interest rates on existing variable rate debt, an $11 million decrease in other interest costs, and a $2 million increase in capitalized interest as compared to 2009. The 2010 decrease was largely offset by a $29 million increase associated with $1.0 billion in additional debt outstanding at December 31, 2010 compared to December 31, 2009.

Income Taxes

Income taxes increased $179 million in 2011 primarily due to higher pre-tax earnings as compared to 2010, 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.

Income taxes increased $126 million in 2010 primarily due to higher pre-tax earnings as compared to 2009, a decrease in the Internal Revenue Code of 1986, as amended, Section 199 production activities deduction, and an increase in Alabama state taxes due to a decrease in the state deduction for federal income taxes paid. Partially offsetting this increase were state tax credits at Georgia Power and tax benefits associated with the construction of a biomass facility at Southern Power. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

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 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	
	2011	2011	2010
		(in millions)	
Operating revenues	$ 70	$ (12)	$ (19)
Other operations and maintenance	96	(9)	(21)
MC Asset Recovery litigation settlement	-	-	(202)
Depreciation and amortization	17	(1)	(9)
Taxes other than income taxes	2	-	-
Total operating expenses	115	(10)	(232)
Operating income (loss)	(45)	(2)	213
Equity in income (losses) of unconsolidated subsidiaries	(2)	-	(1)
Leveraged lease income (losses)	25	7	(22)
Other income (expense), net	(9)	6	(19)
Interest expense	54	(8)	(9)
Income taxes	(74)	14	4
Net income (loss)	$ (11)	$ 5	$ 176

Operating Revenues

Southern Company's non-electric operating revenues from these other business activities decreased $12 million in 2011 primarily as a result of a decrease in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry. The $19 million decrease in 2010 primarily resulted from a decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other businesses decreased $9 million in 2011 and $21 million in 2010. These decreases were primarily the result of lower administrative and general expenses for these other businesses.

MC Asset Recovery Litigation Settlement

In March 2009, Southern Company entered into a litigation settlement agreement with MC Asset Recovery, LLC (MC Asset Recovery) which resulted in a charge of $202 million and required MC Asset Recovery to release Southern Company and certain other designated avoidance actions assigned to MC Asset Recovery in connection with Mirant Corporation's plan of reorganization, as well as to release all actions against current or former officers and directors of Mirant Corporation and Southern Company that had or could have been filed. Pursuant to the settlement, Southern Company recorded a charge in the first quarter 2009 of $202 million, which was paid in the second quarter 2009. The settlement has been completed and resolves all claims by MC Asset Recovery against Southern Company. In June 2009, the case was dismissed with prejudice.

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. Leveraged lease income (losses) increased $7 million in 2011 primarily as a result of changes in the average leveraged lease investment balance. Leveraged lease income (losses) decreased $22 million in 2010 primarily as a result of a $26 million gain recorded in 2009 associated with the early termination of two international leveraged lease investments, the proceeds from which were required to extinguish all debt related to the leveraged lease investments, and a portion of which had make-whole redemption provisions. This resulted in a $17 million loss in 2009, partially offsetting the gain. In addition, leveraged lease income decreased $6 million in 2010 primarily due to lease income no longer being recognized on the terminated leveraged lease investments.

Other Income (Expense), Net

Other income (expense), net for these other businesses increased $6 million in 2011 and decreased $19 million in 2010 primarily as a result of changes in the amount of charitable contributions made by the parent company in 2011 and 2010.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $8 million in 2011 and $9 million in 2010 primarily due to lower average interest rates on existing variable rate debt in the applicable period.

Income Taxes

Income taxes for these other businesses increased $14 million in 2011 primarily as a result of lower pre-tax losses and a prior year state tax adjustment related to leveraged leases. The 2010 increase in income taxes was not material when compared to the prior year.

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 Southern Company'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. 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 area. 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, cost, 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 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 and Note 7 to the financial statements 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 September 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. On March 14, 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.

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. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. 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. On May 27, 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. 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 2011, the traditional operating companies had invested approximately $8.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of $300 million, $500 million, and $1.3 billion for 2011, 2010, and 2009, respectively. The Southern Company system expects that base level capital expenditures to comply with existing statutes and regulations will be a total of approximately $1.5 billion from 2012 through 2014 as follows:

	2012	2013	2014
		(in millions)	
Existing environmental statutes and regulations	$425	$405	$621

The environmental costs that are known and estimable at this time are included under the heading "Capital" in the table under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. These base environmental costs do not include potential incremental environmental compliance investments associated with complying with the EPA's final Mercury and Air Toxics Standards (MATS) rule (formerly referred to as the Utility Maximum Achievable Control Technology rule) or the EPA's proposed water and coal combustion byproducts rules, except with respect to $750 million as described below.

The Southern Company system is assessing the potential costs of complying with the MATS rule, as well as the EPA's proposed water and coal combustion byproducts rules. See "Air Quality," "Water Quality," and "Coal Combustion Byproducts" below for additional information regarding the MATS rule, the proposed water rules, and the proposed coal combustion byproducts rule. Although its analyses are preliminary, the Southern Company system estimates that the aggregate capital costs to the traditional operating companies for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $13 billion to $18 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. Included in this amount is $750 million that is also included in the 2012 through 2014 base level capital investment of the traditional operating companies described herein in anticipation of these rules.

With respect to the impact of the MATS rule on capital spending from 2012 through 2014, the Southern Company system's preliminary analysis anticipates that potential incremental environmental compliance capital expenditures to comply with the MATS rule are likely to be substantial and could be up to $2.7 billion from 2012 through 2014. Additionally, capital expenditures to comply with the proposed water and coal combustion byproducts rules could also be substantial and could be up to $1.5 billion over the same 2012 through 2014 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule. The estimated costs are as follows:

	2012	2013	2014
		(in millions)	
MATS rule	Up to $ 370	Up to $770	Up to $1,610
Proposed water and coal combustion byproducts rules	Up to $40	Up to $365	Up to $1,090
Total potential incremental environmental compliance investments	**Up to $410**	**Up to $1,135**	**Up to $2,700**

The Southern Company system's compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures are dependent on a final assessment of the MATS rule and will be affected by the final requirements of new or revised environmental regulations 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. These costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, the addition of new generating resources, and changing fuel sources for certain existing units. The Southern Company system's preliminary analysis further indicates that the short timeframe for compliance with the MATS rule could significantly affect electric system reliability and cause an increase in costs of materials and services. The ultimate outcome of these matters cannot be determined at this time.

As of December 31, 2011, the Southern Company system had total generating capacity of approximately 43,555 megawatts (MWs), of which 20,212 MWs are coal-fired. Over the past several years, the Southern Company system has installed various pollution control technologies on coal-fired units, including both selective catalytic reduction equipment and scrubbers on the 17 largest coal units making up 11,036 MWs of the Southern Company system's coal-fired generating capacity. As a result of the EPA's final and anticipated rules and regulations, the Southern Company system is evaluating its coal-fired generating capacity and is developing a compliance strategy which may include unit retirements, installation of additional environmental controls (including on the units with existing pollution control technologies), and changing fuel sources for certain units.

Southern Electric Generating Company (SEGCO), jointly owned by Alabama Power and Georgia Power, is also developing an environmental compliance strategy for its 1,000 MWs of coal-fired generating capacity, which may result in unit retirements, installation of controls, or changing fuel source. The capacity of SEGCO's units is sold to Alabama Power and Georgia Power through a PPA. The impact of SEGCO's 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 for additional information.

Compliance with any new federal or state legislation or regulations relating to global climate change, air quality, coal combustion byproducts, water, 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 spent approximately $7.4 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in 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 air quality standard, which it began to implement in September 2011. The 2008 standard is expected to result in designation of new nonattainment areas within the Southern Company system service territory and could require additional reductions in NO_x emissions.

The EPA also regulates fine particulate matter emissions on an annual and 24-hour average basis. Although all areas within the Southern Company system's service territory have air quality levels that attain the current standard, the EPA has announced its intention to propose new, more stringent annual and 24-hour fine particulate matter standards in mid-2012.

Final revisions to the National Ambient Air Quality Standard for SO_2, including the establishment of a new one-hour standard, became effective in August 2010. Since the EPA intends to rely on computer modeling for implementation of the SO_2 standard, the identification of potential nonattainment areas remains uncertain and could ultimately include areas within the Southern Company system's service territory. The EPA is expected to designate areas as attainment and nonattainment under the new standard in 2012. mplementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and ›peration costs.

Revisions to the National Ambient Air Quality Standard for Nitrogen Dioxide (NO_2), which established a new one-hour standard, became effective in April 2010. The EPA signed a final rule with area designations for the new NO_2 standard on January 20, 2012; none of the areas within the Southern Company system's service territory were designated as nonattainment. 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. On April 6, 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 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. On August 8, 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. Like CAIR, the CSAPR was intended to address interstate emissions of SO_2 and NO_x that interfere with downwind states' ability to meet or maintain national ambient air quality standards for ozone and/or particulate matter. Numerous parties (including the traditional operating companies and Southern Power) sought administrative reconsideration of the CSAPR and also filed appeals and requests to stay the rule pending judicial review with the U.S. Court of Appeals for the District of Columbia Circuit. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR in its entirety and ordered the EPA to continue administration of CAIR pending a final decision. Before the stay was granted, the EPA published proposed technical revisions to the CSAPR, including adjustments to certain state emissions budgets and a delay in implementation of the emissions trading limitations until January 2014. On February 7, 2012, the EPA released the final technical revisions to the CSAPR and at the same time issued a direct final rule which together provide increases to certain state emissions budgets, including the states of Florida, Georgia, and Mississippi.

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. On December 30, 2011, the EPA issued a proposed rule providing that compliance with the CSAPR satisfies BART obligations under the CAVR. Given the pending legal challenge to the CSAPR, it remains uncertain 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 – three years after the effective date of the final rule. As described above, compliance with this rule is likely to require substantial capital expenditures and compliance costs at many of the facilities of Southern Company's subsidiaries which could affect unit retirement and replacement decisions. In addition, results of operations, cash flows, and financial condition could be affected if the costs are not recovered through regulated rates. Further, there is uncertainty regarding the ability of the electric utility industry to achieve compliance with the requirements of the rule within the compliance period, and the limited compliance period could negatively affect electric system reliability.

On March 21, 2011, the EPA published the final Industrial Boiler (IB) Maximum Achievable Control Technology (MACT) rule establishing emissions limits for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. At the same time, the EPA issued a notice of intent to reconsider the final rule and, on May 16, 2011, the EPA issued an administrative stay to prevent the rule from becoming effective. On December 2, 2011, the EPA proposed a reconsideration rule to change certain aspects of the final rule. On January 9, 2012, however, the U.S. District Court for the District of Columbia Circuit vacated the EPA's administrative stay. Although the U.S. District Court for the District of Columbia Circuit's decision would allow the original IB MACT rule to become effective, the EPA has indicated that it will not implement the rule until the EPA's proposed revisions can be finalized. The effect of the regulatory proceedings will depend on the final form of the revised regulations and the outcome of any legal challenges and cannot be determined at this time. On October 18, 2011, the Georgia PSC approved Georgia Power's request to further delay the decision to convert Plant Mitchell Unit 3 from coal to biomass for two to four years, until there is greater clarity regarding the IB MACT rule and other proposed and recently adopted regulations.

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, the CSAPR, the CAIR, the CAVR, the MATS rule, and the IB MACT rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the final rules, resolution of pending and future legal challenges, and the development and implementation of rules at the state level. However, 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, 2011, 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. As a result of uncertainties related to the potential federal air quality regulations described above, Georgia Power has suspended certain work related to the installation of emissions control equipment at Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7. Georgia Power continues to analyze the potential costs and benefits of installing the required controls on its remaining coal-fired generating units in light of the potential federal regulations described above. Georgia Power may determine that retiring and replacing certain of these existing units with new generating resources or purchased power is more economically efficient than installing the required environmental controls. See "PSC Matters – Georgia Power – 2011 Integrated Resource Plan Update" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Water Quality

On April 20, 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' generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA has agreed in a settlement agreement to issue a final rule by July 27, 2012. 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 adopt such revisions by January 2014. New wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Southern Company system facilities, which could result in significant additional capital expenditures and compliance costs, as described above, that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the studies conducted in connection with the rulemaking, as well as the specific 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, including both "wet" (ash ponds) and "dry" (landfill) 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 is currently evaluating whether additional regulation of coal combustion byproducts (including coal ash and gypsum) is merited under federal solid and hazardous waste laws. In June 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. On January 18, 2012, several environmental organizations notified the EPA of their intent to file a lawsuit over the delay of a final coal combustion byproducts rule unless the EPA finalizes the coal combustion byproducts rule on or before March 19, 2012, which is within 60 days of the date on which the organizations filed their notice of intent to file a lawsuit.

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, as described above, 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 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

Over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions and mandate renewable or clean energy. The financial and operational impacts of climate or energy legislation, if enacted, would depend on a variety of factors, including the specific provisions and timing of any legislation that might ultimately be adopted. Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions, renewable or clean energy standards, and/or energy efficiency standards are expected to continue to be considered by the U.S. Congress.

In 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles, and, in April 2010, the EPA issued regulations to that effect. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The Tailoring Rule requires that new sources that potentially emit over 100,000 tons per year of greenhouse gases and projects at existing sources that increase emissions by over 75,000 tons per year of greenhouse gases must go through the PSD permitting process and install the best available control technology for carbon dioxide and other greenhouse gases. In addition to these rules, the EPA has announced plans to propose a rule setting forth standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units in early 2012 and greenhouse gas emissions guidelines for existing sources in late 2012.

Each of the EPA's final Clean Air Act rulemakings have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. These rules may impact the amount of time it takes to obtain PSD permits for new generation and major modifications to existing generating units and the requirements ultimately imposed by those permits. The ultimate impact of these rules cannot be determined at this time and will depend on the outcome of any legal challenges.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. In 2009, a nonbinding agreement known as the Copenhagen Accord was reached that included a pledge from countries to reduce their greenhouse gas emissions. The 2011 negotiations established a process for development of a legal instrument applicable to all countries by 2016, to be effective in 2020. The outcome and impact of the international negotiations cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, mandatory 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 are likely to result in significant additional compliance costs, including significant 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. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information. 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 new EPA greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons, based on a company's operational control of facilities. Using the methodology of the rule and based on ownership or financial control of facilities, the Southern Company system's 2010 greenhouse gas emissions were approximately 137 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Southern Company system's 2011 greenhouse gas emissions on the same basis is approximately 125 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.

The Southern Company system is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. These include, but are not limited to: new nuclear generation, including Plant Vogtle Units 3 and 4; construction of the Kemper IGCC with approximately 65% carbon capture; and renewable investments, including the construction of a biomass plant in Sacul, Texas and Alabama Power's purchase of approximately 400 MWs of energy from renewable sources, including wind energy (some of which remains subject to regulatory approval). In addition, Southern Power completed construction on a solar photovoltaic plant near Cimarron, New Mexico in 2010. The Southern Company system is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies.

PSC Matters

Alabama Power

Retail Rate Adjustments

On July 12, 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.

Rate RSE

Alabama Power operates under 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, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, Alabama Power agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

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 and the recovery of retail costs associated with certificated PPAs under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, Alabama Power had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

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. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, 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, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that Alabama Power leave in effect for 2012 the factors associated with Alabama Power's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, Alabama Power had an under recovered environmental clause balance of $11 million which is included in deferred 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. On September 7, 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 – General" herein for additional information regarding environmental regulations.

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 discretionary authority to accrue certain additional amounts as circumstances warrant.

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.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows Alabama Power to make additional accruals to the NDR. The order also 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. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

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 on April 27, 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 on July 12, 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 balance in the NDR for the year ended December 31, 2011 was approximately $110 million.

For the year ended December 31, 2010, Alabama Power accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

In August 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 new 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 new accounting order is 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, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be 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 December 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 or will be made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Other Construction" below for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, Georgia Power's 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. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2010 ARP is in effect. Georgia Power is required to file a general 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.

2011 Integrated Resource Plan Update

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," " – Water Quality," and " – Coal Combustion Byproducts" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Rate Plans" 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 August 4, 2011, Georgia Power filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included Georgia Power's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. Georgia Power also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, Georgia Power is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 MWs of capacity. Georgia Power is currently updating its economic analysis of these units based on the final MATS rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, Georgia Power cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes Georgia Power's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process.

In addition, Georgia Power filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, Georgia Power entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

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 Integrated Resource Plan 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 decision, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 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 and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Southern Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. In previous years, the traditional operating companies experienced volatility in pricing of fuel commodities with higher than expected pricing for coal and uranium and volatile price swings in natural gas. This volatility and higher fuel costs have resulted in total under recovered fuel costs included in the balance sheets of Alabama Power and Georgia Power of approximately $169 million at December 31, 2011. Gulf Power and Mississippi Power collected all previously under recovered fuel costs and, as of December 31, 2011, had a total over recovered fuel balance of approximately $52 million. At December 31, 2010, total under recovered fuel costs included in the balance sheets of Alabama Power, Georgia Power, and Gulf Power were approximately $420 million, and Mississippi Power had a total over recovered fuel balance of approximately $55 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 the 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 – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery," for additional information.

Income Tax Matters

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. In 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, Georgia Power and the Georgia DOR agreed to a settlement resolving the claims. As a result, Georgia Power recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, Georgia Power recorded a reduction of approximately $23 million in related interest expense. See Note 3 under "Retail Regulatory Matters – Georgia Power – Other Construction" and "Income Tax Matters – Georgia State Income Tax Credits" for additional information on this regulatory liability.

Bonus Depreciation

In September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 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 construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Company through 2013. Due to the significant amount of estimated bonus depreciation for 2012, tax credit utilization will be reduced. Consequently, it is estimated there will be a positive cash flow benefit of between $400 million and $550 million in 2012.

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. Southern Company intends to continue its strategy of developing and constructing new generating facilities, including natural gas and biomass units at Southern Power, natural gas units and Plant Vogtle Units 3 and 4 at Georgia Power, and the Kemper IGCC at Mississippi Power, as well as 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. See Note 7 to the financial statements under "Construction Program" for estimated construction expenditures for the next three years. In addition, see Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other 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 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.

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 asset. Southern Company will continue to monitor the performance of the underlying assets and to evaluate the ability of the lessee to continue to make the required lease payments. While there are strategic options that Southern Company may pursue to recover its investment in the leveraged lease, the potential impairment loss that would be incurred if there is an abandonment of the project 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 and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, 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.

On March 11, 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 Nuclear Regulatory Commission (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 July 12, 2011, a special NRC task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S., including potential changes in emergency planning, onsite backup generation, and spent fuel pools for reactors. 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. 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.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with generally accepted accounting principles (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 96% of Southern Company's total operating revenues for 2011, 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 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.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Alabama Power is able to determine a significant amount of metered unbilled KWH sales due to the installation of automated meters. At the end of each month, amounts of electricity delivered are read for the customers with automated meters. From this reading, unbilled KWH sales are determined and included in Alabama Power's unbilled revenue calculation. Estimates of unbilled electricity delivered are made when automated meter readings are not available.

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 2012	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2011	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2011
		(in millions)	
25 basis point change in discount rate	\$28/\$(26)	\$287/\$(272)	\$54/\$(51)
25 basis point change in salaries	\$14/\$(14)	\$73/\$(70)	\$-/\$-
25 basis point change in long-term return on plan assets	\$20/\$(20)	N/A	N/A

N/A – Not applicable

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2011. 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 2012 through 2014, 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 remained stable in value as of December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. Southern Company does not expect any material changes to funding obligations to the nuclear decommissioning trust funds prior to 2014.

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 provided from operating activities in 2010 totaled \$4 billion, an increase of \$728 million from the corresponding period in 2009. Significant changes in operating cash flow for 2010 as compared to the corresponding period in 2009 include an increase in net income, a reduction in fossil fuel stock, and an increase in deferred income taxes primarily due to the change in the tax accounting method for repair costs. A contribution to the qualified pension plan partially offset these increases.

Net cash used for investing activities in 2011 totaled \$4.2 billion primarily due to property additions to utility plant. Net cash used for investing activities in 2010 totaled \$4.3 billion primarily due to property additions to utility plant. Net cash used for investing activities in 2009 totaled \$4.3 billion primarily due to property additions to utility plant of \$4.7 billion, partially offset by approximately \$340 million in cash received from the early termination of two leveraged lease investments.

Net cash used for financing activities totaled \$852 million in 2011, compared to \$22 million net cash provided from financing activities in 2010. This change was primarily due to a reduction of short-term debt outstanding and redemptions of long-term debt in 2011. Net cash provided from financing activities totaled \$22 million in 2010, a decrease of \$1.3 billion from the corresponding period in 2009. This decrease was primarily due to redemptions of long-term debt in 2010.

Significant balance sheet changes in 2011 include an increase of $3.0 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 an increase in cash of $868 million due to increased cash collection from operations, an increase in deferred income taxes of $1.3 billion due to bonus depreciation and a change in the tax accounting method for repair costs, and $1.4 billion of additional equity.

At the end of 2011, the closing price of Southern Company's common stock was $46.29 per share, compared with a book value of $20.32 per share. The market-to-book value ratio was 228% at the end of 2011, compared with 199% at year-end 2010.

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 2012, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

Except as described below with respect to potential U.S. Department of Energy (DOE) loan guarantees, 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 June 2010, Georgia Power reached an agreement with the 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. There can be no assurance that the DOE will issue loan guarantees for Georgia Power.

In addition, Mississippi Power has applied to the DOE for federal loan guarantees to finance a portion of the eligible construction costs of the Kemper IGCC. Mississippi Power is in advanced due diligence with the DOE. There can be no assurance that the DOE will issue federal loan guarantees for Mississippi Power. Mississippi Power also received DOE Clean Coal Power Initiative Round 2 grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for the initial operation 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.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. 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, 2011, Southern Company and its subsidiaries had approximately $1.3 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2011 were as follows:

	Expires[a]						Due Within One Year		Executable Term-Loans	
Company	2012	2013	2014	2016	Total	Unused	Term Out	No Term Out	One Year	Two Years
		(in millions)			(in millions)		(in millions)		(in millions)	
Southern Company	$ -	$ -	$ -	$1,000	$1,000	$1,000	$ -	$ -	$ -	$ -
Alabama Power	121	35	350	800	1,306	1,306	51	71	51	-
Georgia Power	-	-	250	1,500	1,750	1,745	-	-	-	-
Gulf Power	75	-	165	-	240	240	75	-	75	-
Mississippi Power	131	-	165	-	296	296	66	65	25	41
Southern Power	-	-	-	500	500	500	-	-	-	-
Other	25	25	-	-	50	50	25	-	25	-
Total	$352	$60	$930	$3,800	$5,142	$5,137	$217	$136	$176	$41

(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 typically 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 requiring liquidity support as of December 31, 2011 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, excluding notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period[a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2011:					
Commercial paper	$654	0.28%	$697	0.29%	$1,586
Short-term bank debt	200	1.18%	14	1.21%	200
Total	$854	0.49%	$711	0.32%	
December 31, 2010:					
Commercial paper	$1,295	0.32%	$690	0.29%	$1,305

(a) Average and maximum amounts are based upon daily balances during the period.

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 2011, Southern Company issued approximately 21.9 million shares of common stock for $723 million through the Southern Investment Plan and employee and director stock plans. The proceeds were primarily used for general corporate purposes, including the investment by Southern Company in its subsidiaries, and to repay short-term indebtedness. While Southern Company continues to issue additional equity through its employee and director equity compensation plans, Southern Company is not currently issuing additional 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 debt financing activities for Southern Company, the traditional operating companies, and Southern Power for the year ended December 31, 2011:

Company	Senior Note Issuances	Senior Note Redemptions and Maturities	Pollution Control Bond Issuances and Remarketings(*)	Pollution Control Bond Repurchases, Redemptions, and Maturities	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities
			(in millions)			
Southern Company	$ 500	$ 300	$ -	$ -	$ -	$ -
Alabama Power	700	750	-	4	-	-
Georgia Power	550	427	604	339	250	509
Gulf Power	125	-	-	-	-	110
Mississippi Power	300	-	-	-	115	130
Southern Power	575	575	-	-	-	3
Total	$ 2,750	$ 2,052	$ 604	$ 343	$ 365	$ 752

(*) Reflects the remarketing of pollution control bonds that had been purchased and held.

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, to fund acquisitions, and for general corporate purposes, including their respective continuous construction programs.

In August 2011, Southern Company issued $500 million aggregate principal amount of Series 2011A 1.95% Senior Notes due September 1, 2016. The net proceeds from the sale of the Series 2011A Senior Notes were used to repay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

In October 2011, Southern Company's $300 million aggregate principal amount of Series 2009B Floating Rate Senior Notes matured.

In March 2011, Alabama Power settled $200 million of interest rate hedges related to its Series 2011A 5.50% Senior Note issuance at a gain of approximately $4 million. The gain is being amortized to interest expense, in earnings, over 10 years.

In August 2011, Alabama Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $300 million.

In September 2011, Mississippi Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes related to anticipated debt issuances. The notional amount of the swaps totaled $600 million. Mississippi Power also settled $300 million of the interest rate swaps in October 2011; $150 million related to its Series 2011A 2.35% Senior Note issuance at a gain of approximately $1.4 million which is being amortized to interest expense, in earnings, over five years; and $150 million related to its Series 2011B 4.75% Senior Note issuance at a loss of approximately $0.5 million which is being amortized to interest expense, in earnings, over 10 years.

In October 2011, 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 as described under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by the combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4) and certain personal property.

In November 2011, Alabama Power entered into forward-looking interest rate swaps to mitigate exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $100 million.

Subsequent to December 31, 2011, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

Subsequent to December 31, 2011, Alabama Power issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including Alabama Power's continuous construction program. In November 2011, Alabama Power entered into forward-starting interest rate swaps to mitigate exposure to interest rate changes in anticipation of this debt issuance. The notional amount of the swaps totaled $100 million and settled subsequent to December 31, 2011, at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

Subsequent to December 31, 2011, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012. Also, Alabama Power announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

Subsequent to December 31, 2011, Georgia Power entered into a floating rate six-month short-term bank loan in an aggregate amount of $100 million, bearing interest based on one-month LIBOR. The proceeds were used for general corporate purposes, including Georgia 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. On July 20, 2011, Mississippi Power provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4.

On October 20, 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 are 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 on July 25, 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized Mississippi Power to defer 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. On November 2, 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 does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change 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, 2011 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$ 9
At BBB- and/or Baa3	613
Below BBB- and/or Baa3	2,812

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact Southern Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. The Company may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to 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, 2011 have a notional amount of $1.1 billion and are related to fixed and floating rate obligations over the next several years. The weighted average interest rate on $3.7 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2012 was 0.81%. 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 $37 million at January 1, 2012. 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 or heat-rate contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into 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.

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

	2011 Changes	2010 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (196)**	$ (178)
Contracts realized or settled	**179**	197
Current period changes[a]	**(214)**	(215)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (231)**	$ (196)

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

The change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2011 was a decrease of $35 million, substantially all of which is due to natural gas positions. The change is attributable to both the volume of million British thermal units (mmBtu) and the price of natural gas. At December 31, 2011, Southern Company had a net hedge volume of 189 million mmBtu with a weighted average swap contract cost approximately $1.51 per mmBtu above market prices, compared to a net hedge volume of 149 million mmBtu at December 31, 2010 with a weighted average swap contract cost approximately $1.35 per mmBtu above market prices. 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	**2011**	2010
	(in millions)	
Regulatory hedges	**$ (221)**	$ (193)
Cash flow hedges	**(1)**	(1)
Not designated	**(9)**	(2)
Total fair value	**$ (231)**	$ (196)

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, 2011, 2010, and 2009 for energy-related derivative contracts that are not hedges were $(6) million, $(2) million, and $(5) 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 and the level of the fair value hierarchy in which they fall at December 31, 2011 were as follows:

	Fair Value Measurements December 31, 2011			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ -	$ -	$ -	$ -
Level 2	(231)	(164)	(65)	(2)
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(231)	$(164)	$(65)	$(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 Investors Service and Standard & Poor's, a division of The McGraw Hill Companies, Inc., 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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in July 2010 could impact the use of over-the-counter derivatives by the Company. Regulations to implement the Dodd-Frank Act could impose additional requirements on the use of over-the-counter derivatives, such as margin and reporting requirements, which could affect both the use and cost of over-the-counter derivatives. The impact, if any, cannot be determined until regulations are finalized.

Southern Company performs periodic reviews of its leveraged lease transactions, both domestic and international and the creditworthiness of the lessees, including a review of the value of the underlying leased assets and the credit ratings of the lessees. Southern Company's domestic lease transactions generally do not have any credit enhancement mechanisms; however, the lessees in its international lease transactions have pledged various deposits as additional security to secure the obligations. The lessees in the Company's international lease transactions are also required to provide additional collateral in the event of a credit downgrade below a certain level.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Potential incremental environmental compliance investments to comply with the MATS rule and with the proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment, except as detailed below. Although its analyses are preliminary, Southern Company estimates that the aggregate capital costs to the traditional operating companies for compliance with the MATS rule and the proposed water and coal combustion byproducts rules could range from $13 billion to $18 billion through 2021, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rules. Included in this amount is approximately $750 million that is also included in the 2012 through 2014 base level capital investment of the traditional operating companies described herein in anticipation of these rules. The Southern Company system's base level construction program and the potential incremental environmental compliance investments for the MATS rule and the proposed water and coal combustion byproducts rules over the next three years, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2012	2013	2014
Construction program:		*(in millions)*	
Base capital	$4,842	$3,976	$3,720
Existing environmental statutes and regulations	425	405	621
Total construction program base level capital investment	**$5,267**	**$4,381**	**$4,341**
Potential incremental environmental compliance investments:			
MATS rule	Up to $ 370	Up to $770	Up to $1,610
Proposed water and coal combustion byproducts rules	Up to $40	Up to $365	Up to $1,090
Total potential incremental environmental compliance investments	**Up to $410**	**Up to $1,135**	**Up to $2,700**

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements, to meet new 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," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Integrated Coal Gasification Combined Cycle" and Note 7 to the financial statements under "Construction Program" 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

	2012	2013-2014	2015-2016	After 2016	Uncertain Timing[(d)]	Total
			(in millions)			
Long-term debt[(a)] –						
Principal	$1,693	$2,523	$2,443	$13,566	$ -	$20,225
Interest	865	1,532	1,379	10,679	-	14,455
Preferred and preference stock dividends[(b)]	65	130	130	-	-	325
Energy-related derivative obligations[(c)]	173	70	2	-	-	245
Interest rate derivative obligations[(c)]	33	-	-	-	-	33
Foreign currency derivative obligations[(c)]	3	-	-	-	-	3
Operating leases	121	183	75	85	-	464
Capital leases	24	28	13	28	-	93
Unrecognized tax benefits and interest[(d)]	25	-	-	-	105	130
Purchase commitments[(e)] –						
Capital[(f)]	4,808	7,794	-	-	-	12,602
Limestone[(g)]	41	84	51	70	-	246
Coal	3,266	3,554	892	737	-	8,449
Nuclear fuel	353	403	237	740	-	1,733
Natural gas[(h)]	1,479	2,749	1,935	2,798	-	8,961
Purchased power	259	529	612	2,700	-	4,100
Long-term service agreements[(i)]	123	302	349	1,141	-	1,915
Trusts –						
Nuclear decommissioning[(j)]	2	3	3	34	-	42
Pension and other postretirement benefit plans[(k)]	100	196	-	-	-	296
Total	$13,433	$20,080	$8,121	$32,578	$ 105	$74,317

(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, 2012, 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 $105 million in unrecognized tax benefits and corresponding interest payments 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 Notes 3 and 5 to the financial statements for additional information.

(e) Southern Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2011, 2010, and 2009 were $3.9 billion, $4.0 billion, and $3.5 billion, respectively.

(f) The Southern Company system provides forecasted capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. In addition, such amounts exclude the Southern Company system's estimates of other potential incremental environmental compliance investments to comply with the MATS rule and the proposed water and coal combustion byproducts rules which are likely to be substantial and could be up to $410 million for 2012, up to $1.1 billion for 2013, and up to $2.7 billion for 2014. At December 31, 2011, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Southern Company system's program to reduce SO_2 emissions from its coal plants, the traditional operating companies have entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2011.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for Georgia Power.

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

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2011 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, future earnings, dividend payout ratios, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Small Business Jobs and Credit Act of 2010, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, 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, implementation of the Energy Policy Act of 2005, 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), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities;
- 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 actions related to the Kemper IGCC, including Mississippi PSC approvals, potential DOE loan guarantees, the South Mississippi Electric Power Association purchase decision, and utilization of investment tax credits;
- 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 Southern Company'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 Southern Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2011, 2010, and 2009

Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Revenues:			
Retail revenues	**$15,071**	$14,791	$13,307
Wholesale revenues	**1,905**	1,994	1,802
Other electric revenues	**611**	589	533
Other revenues	**70**	82	101
Total operating revenues	**17,657**	17,456	15,743
Operating Expenses:			
Fuel	**6,262**	6,699	5,952
Purchased power	**608**	563	474
Other operations and maintenance	**3,938**	4,010	3,526
MC Asset Recovery litigation settlement	**-**	-	202
Depreciation and amortization	**1,717**	1,513	1,503
Taxes other than income taxes	**901**	869	818
Total operating expenses	**13,426**	13,654	12,475
Operating Income	**4,231**	3,802	3,268
Other Income and (Expense):			
Allowance for equity funds used during construction	**153**	194	200
Interest expense, net of amounts capitalized	**(857)**	(895)	(905)
Other income (expense), net	**(40)**	(35)	41
Total other income and (expense)	**(744)**	(736)	(664)
Earnings Before Income Taxes	**3,487**	3,066	2,604
Income taxes	**1,219**	1,026	896
Consolidated Net Income	**2,268**	2,040	1,708
Dividends on Preferred and Preference Stock of Subsidiaries	**65**	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	**$ 2,203**	$ 1,975	$ 1,643
Common Stock Data:			
Earnings per share (EPS)–			
Basic EPS	**$2.57**	$2.37	$2.07
Diluted EPS	**2.55**	2.36	2.06
Average number of shares of common stock outstanding – (in millions)			
Basic	**857**	832	795
Diluted	**864**	837	796
Cash dividends paid per share of common stock	**$1.8725**	$1.8025	$1.7325

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2011, 2010, and 2009

Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in millions)	
Consolidated Net Income	**$2,268**	$2,040	$1,708
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(10), $-, and $(3), respectively	**(18)**	(1)	(4)
Reclassification adjustment for amounts included in net income, net of tax of $6, $9, and $18, respectively	**9**	15	28
Marketable securities:			
Change in fair value, net of tax of $(2), $(2), and $1, respectively	**(4)**	(3)	4
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss),net of tax of $(1), $1, and $(8), respectively	**(2)**	6	(12)
Reclassification adjustment for amounts included in net income, net of tax of $(14), $1, and $1, respectively	**(26)**	1	1
Total other comprehensive income (loss)	**(41)**	18	17
Dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Consolidated Comprehensive Income	**$2,162**	$1,993	$1,660

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2011, 2010, and 2009

Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 2,268**	$ 2,040	$ 1,708
Adjustments to reconcile consolidated net income to net cash provided from operating activities --			
Depreciation and amortization, total	**2,048**	1,831	1,788
Deferred income taxes	**1,155**	1,038	25
Deferred revenues	**(4)**	(103)	(54)
Allowance for equity funds used during construction	**(153)**	(194)	(200)
Pension, postretirement, and other employee benefits	**(45)**	(614)	(3)
Stock based compensation expense	**42**	33	23
Generation construction screening costs	**-**	(51)	(22)
Other, net	**19**	70	43
Changes in certain current assets and liabilities --			
-Receivables	**362**	80	585
-Fossil fuel stock	**(62)**	135	(432)
-Materials and supplies	**(60)**	(30)	(39)
-Other current assets	**(17)**	(17)	(47)
-Accounts payable	**(5)**	4	(125)
-Accrued taxes	**330**	(308)	(95)
-Accrued compensation	**10**	180	(226)
-Other current liabilities	**15**	(103)	334
Net cash provided from operating activities	**5,903**	3,991	3,263
Investing Activities:			
Property additions	**(4,525)**	(4,086)	(4,670)
Distribution of restricted cash	**63**	25	119
Nuclear decommissioning trust fund purchases	**(2,195)**	(2,009)	(1,234)
Nuclear decommissioning trust fund sales	**2,190**	2,004	1,228
Proceeds from property sales	**25**	18	340
Cost of removal, net of salvage	**(93)**	(125)	(119)
Change in construction payables	**191**	(51)	215
Other investing activities	**161**	(32)	(198)
Net cash used for investing activities	**(4,183)**	(4,256)	(4,319)
Financing Activities:			
Increase (decrease) in notes payable, net	**(438)**	659	(306)
Proceeds --			
Long-term debt issuances	**3,719**	3,151	3,042
Common stock issuances	**723**	772	1,286
Redemptions and repurchases --			
Long-term debt	**(3,170)**	(2,966)	(1,234)
Payment of common stock dividends	**(1,601)**	(1,496)	(1,369)
Payment of dividends on preferred and preference stock of subsidiaries	**(65)**	(65)	(65)
Other financing activities	**(20)**	(33)	(25)
Net cash provided from (used for) financing activities	**(852)**	22	1,329
Net Change in Cash and Cash Equivalents	**868**	(243)	273
Cash and Cash Equivalents at Beginning of Year	**447**	690	417
Cash and Cash Equivalents at End of Year	**$ 1,315**	$ 447	$ 690

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2011 and 2010
Southern Company and Subsidiary Companies 2011 Annual Report

Assets	2011	2010
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,315**	$ 447
Restricted cash and cash equivalents	**8**	68
Receivables --		
Customer accounts receivable	**1,074**	1,140
Unbilled revenues	**376**	420
Under recovered regulatory clause revenues	**143**	209
Other accounts and notes receivable	**282**	285
Accumulated provision for uncollectible accounts	**(26)**	(25)
Fossil fuel stock, at average cost	**1,367**	1,308
Materials and supplies, at average cost	**903**	827
Vacation pay	**160**	151
Prepaid expenses	**385**	784
Other regulatory assets, current	**239**	210
Other current assets	**46**	59
Total current assets	**6,272**	5,883
Property, Plant, and Equipment:		
In service	**59,744**	56,731
Less accumulated depreciation	**21,154**	20,174
Plant in service, net of depreciation	**38,590**	36,557
Other utility plant, net	**55**	-
Nuclear fuel, at amortized cost	**774**	670
Construction work in progress	**5,591**	4,775
Total property, plant, and equipment	**45,010**	42,002
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,207**	1,370
Leveraged leases	**649**	624
Miscellaneous property and investments	**262**	277
Total other property and investments	**2,118**	2,271
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,365**	1,280
Prepaid pension costs	**-**	88
Unamortized debt issuance expense	**156**	178
Unamortized loss on reacquired debt	**285**	274
Deferred under recovered regulatory clause revenues	**48**	218
Other regulatory assets, deferred	**3,532**	2,402
Other deferred charges and assets	**481**	436
Total deferred charges and other assets	**5,867**	4,876
Total Assets	**$59,267**	$55,032

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2011 and 2010

Southern Company and Subsidiary Companies 2011 Annual Report

Liabilities and Stockholders' Equity	**2011**	2010
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 1,717**	$ 1,301
Notes payable	**859**	1,297
Accounts payable	**1,553**	1,275
Customer deposits	**347**	332
Accrued taxes --		
Accrued income taxes	**13**	8
Unrecognized tax benefits	**22**	187
Other accrued taxes	**425**	440
Accrued interest	**226**	225
Accrued vacation pay	**205**	194
Accrued compensation	**450**	438
Liabilities from risk management activities	**209**	152
Other regulatory liabilities, current	**125**	88
Other current liabilities	**426**	535
Total current liabilities	**6,577**	6,472
Long-Term Debt (See accompanying statements)	**18,647**	18,154
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**8,809**	7,554
Deferred credits related to income taxes	**224**	235
Accumulated deferred investment tax credits	**611**	509
Employee benefit obligations	**2,442**	1,580
Asset retirement obligations	**1,321**	1,257
Other cost of removal obligations	**1,165**	1,158
Other regulatory liabilities, deferred	**297**	312
Other deferred credits and liabilities	**514**	517
Total deferred credits and other liabilities	**15,383**	13,122
Total Liabilities	**40,607**	37,748
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**375**	375
Total Stockholders' Equity (See accompanying statements)	**18,285**	16,909
Total Liabilities and Stockholders' Equity	**$59,267**	$55,032
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31, 2011 and 2010

Southern Company and Subsidiary Companies 2011 Annual Report

		2011	2010	**2011**	2010
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts --					
Maturity	Interest Rates				
2044	5.88%	**$ -**	$ 206		
Variable rate (3.68% at 1/1/12) due 2042		**206**	206		
Total long-term debt payable to affiliated trusts		**206**	412		
Long-term senior notes and debt --					
Maturity	Interest Rates				
2011	4.00% to 5.57%	**-**	304		
2012	4.85% to 6.25%	**1,203**	1,778		
2013	1.30% to 6.00%	**1,436**	1,436		
2014	4.15% to 4.90%	**437**	425		
2015	2.38% to 5.25%	**1,175**	1,184		
2016	1.95% to 5.30%	**1,210**	310		
2017 through 2051	2.25% to 8.20%	**9,797**	9,128		
Variable rates (0.56% to 0.78% at 1/1/11) due 2011		**-**	915		
Variable rates (0.60% to 0.95% at 1/1/12) due 2012		**490**	-		
Variable rates (0.85% to 0.90% at 1/1/12) due 2013		**650**	350		
Variable rate (0.44% at 1/1/11) due 2040		**-**	50		
Total long-term senior notes and debt		**16,398**	15,880		
Other long-term debt --					
Pollution control revenue bonds --					
Maturity	Interest Rates				
2016	4.40%	**-**	67		
2018 through 2049	0.75% to 6.00%	**1,590**	1,740		
Variable rate (0.39% at 1/1/11) due 2011		**-**	8		
Variable rate (0.07% at 1/1/12) due 2015		**54**	54		
Variable rate (0.16% at 1/1/12) due 2016		**4**	4		
Variable rates (0.03% to 0.18% at 1/1/12) due 2017 to 2049		**1,703**	1,218		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	-		
Total other long-term debt		**3,621**	3,091		
Capitalized lease obligations		**93**	99		
Unamortized debt premium (related to plant acquisition)		**78**	1		
Unamortized debt discount		**(32)**	(28)		
Total long-term debt (annual interest requirement -- $865 million)		**20,364**	19,455		
Less amount due within one year		**1,717**	1,301		
Long-term debt excluding amount due within one year		**18,647**	18,154	**50.0%**	51.2%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)

At December 31, 2011 and 2010

Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2011	2010
	(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**	1.1
Common Stockholders' Equity:				
Common stock, par value $5 per share --	**4,328**	4,219		
Authorized - 1.5 billion shares				
Issued -- 2011: 866 million shares				
-- 2010: 844 million shares				
Treasury -- 2011: 0.5 million shares				
-- 2010: 0.5 million shares				
Paid-in capital	**4,410**	3,702		
Treasury, at cost	**(17)**	(15)		
Retained earnings	**8,968**	8,366		
Accumulated other comprehensive income (loss)	**(111)**	(70)		
Total common stockholders' equity	**17,578**	16,202	**47.1**	45.7
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	**1.9**	2.0
Total stockholders' equity	**18,285**	16,909		
Total Capitalization	**$37,307**	$35,438	**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, 2011, 2010, and 2009

Southern Company and Subsidiary Companies 2011 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, 2008	777,616	(424)	$3,888	$1,893	$(12)	$7,612	$(105)	$707	$13,983
Net income after dividends on preferred and preference stock of subsidiaries	-	-	-	-	-	1,643	-	-	1,643
Other comprehensive income (loss)	-	-	-	-	-	-	17	-	17
Stock issued	42,536	-	213	1,074	-	-	-	-	1,287
Stock-based compensation	-	-	-	26	-	-	-	-	26
Cash dividends	-	-	-	-	-	(1,369)	-	-	(1,369)
Other	-	(81)	-	2	(3)	(1)	-	-	(2)
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**

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (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 Southern Company'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:

	2011	2010	Note
	(in millions)		
Deferred income tax charges	**$ 1,293**	$ 1,204	(a)
Deferred income tax charges – Medicare subsidy	**77**	82	(j)
Asset retirement obligations-asset	**117**	79	(a,h)
Asset retirement obligations-liability	**(42)**	(82)	(a,h)
Other cost of removal obligations	**(1,196)**	(1,188)	(a)
Deferred income tax credits	**(225)**	(237)	(a)
State income tax credits	**(62)**	-	(k)
Loss on reacquired debt	**285**	274	(b)
Vacation pay	**160**	151	(c,h)
Under recovered regulatory clause revenues	**50**	27	(d)
Over recovered regulatory clause revenues	**(28)**	(40)	(d)
Building leases	**43**	45	(f)
Generating plant outage costs	**38**	31	(l)
Under recovered storm damage costs	**43**	8	(d)
Property damage reserves	**(206)**	(216)	(g)
Fuel hedging-asset	**249**	211	(d)
Fuel hedging-liability	**(13)**	(7)	(d)
Other assets	**290**	171	(d)
Environmental remediation-asset	**71**	67	(g,h)
Environmental remediation-liability	**(8)**	(10)	(g)
Other liabilities	**(30)**	(13)	(i)
Retiree benefit plans	**2,959**	2,041	(e,h)
Total assets (liabilities), net	**$ 3,865**	$ 2,598	

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, 2011, other cost of removal obligations included $62 million that is being amortized over the remaining two-year period in accordance with an Alternate Rate Plan for Georgia Power for the years 2011 through 2013. 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 not exceeding five 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) Recorded and recovered or amortized as approved by the appropriate state PSC over periods up to the life of the plant or the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.
(j) Recovered and amortized as approved by the appropriate state PSCs over periods not exceeding 14 years. See Note 5 under "Current and Deferred Income Taxes" for additional information.
(k) Additional tax benefits resulting from the Georgia state income tax credit settlement that will be amortized over a 21-month period beginning April 2012 in accordance with a Georgia PSC order. See Note 3 under "Income Tax Matters – Georgia State Income Tax Credits" for additional information.
(l) Recovered over the respective operating cycles, which range from 18 months to 10 years. See "Property, Plant, and Equipment" herein for additional information.

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 $19 million in 2011, $23 million in 2010, and $24 million in 2009. At December 31, 2011, 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 $0.9 million in 2011. No credits were amortized in 2010 or 2009. 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:

	2011	2010
	(in millions)	
Generation	**$ 31,751**	$ 30,121
Transmission	**8,240**	7,835
Distribution	**15,458**	14,870
General	**3,413**	3,116
Plant acquisition adjustment	**124**	43
Utility plant in service	**58,986**	55,985
Information technology equipment and software	**220**	216
Communications equipment	**428**	423
Other	**110**	107
Other plant in service	**758**	746
Total plant in service	**$59,744**	$ 56,731

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 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, 2011, 2010, and 2009 was $929 million, $427 million, and $370 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 2001, Mississippi Power began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. On July 20, 2011, Mississippi Power provided notice to the lessor of its intent to purchase Plant Daniel Units 3 and 4. On October 20, 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 has been engaged in acquiring assets. Southern Power has accounted for acquisitions under the acquisition method in accordance with GAAP. The purchase price of each acquisition is allocated to the fair value of the identifiable assets and liabilities, including property, plant, and equipment.

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 2011, 3.3% in 2010, and 3.2% in 2009. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled \$20.7 billion and \$19.7 billion at December 31, 2011 and 2010, 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 Alternate Rate Plan for the years 2011 through 2013 (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 \$456 million and \$441 million at December 31, 2011 and 2010, 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 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:

	2011	2010
	(in millions)	
Balance at beginning of year	**\$1,266**	\$ 1,206
Liabilities incurred	**1**	-
Liabilities settled	**(13)**	(16)
Accretion	**82**	78
Cash flow revisions	**8**	(2)
Balance at end of year	**\$1,344**	\$ 1,266

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 (the 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. In addition, the NRC prohibits investments in securities of power reactor licensees. 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 broad limits, 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 investment brokers 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, 2011 and 2010, approximately $39 million and $141 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 $42 million and $144 million at December 31, 2011 and 2010, 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, 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. At December 31, 2010, investment securities in the Funds totaled $1.4 billion consisting of equity securities of $664 million, debt securities of $632 million, and $74 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 $2.2 billion, $2.0 billion, and $1.2 billion in 2011, 2010, and 2009, respectively, all of which were reinvested. 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. For 2009, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $215 million, of which $198 million related to securities held in the Funds at December 31, 2009. 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, 2011, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
		(in millions)	
External trust funds	$ 540	$ 399	$ 235
Internal reserves	23	-	-
Total	$ 563	$ 399	$ 235

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 2009 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	2063	2067
		(in millions)	
Site study costs:			
Radiated structures	$1,060	$583	$500
Non-radiated structures	72	46	71
Total	$1,132	$629	$571

The decommissioning periods and site study costs for Plant Vogtle reflect the extended operating license approved by the NRC in June 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 as of 2009. Current NRC estimates are $584 million and $426 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Amounts expensed were $3 million annually for Plant Vogtle Units 1 and 2 for 2009 and 2010. Effective for the years 2011 through 2013, the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. Georgia Power projects the Funds for Plant Vogtle Units 1 and 2 would be adequate to meet the decommissioning obligations of the NRC with no further contributions. 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.

As a result of license extensions, 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, it 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 9.1%, 12.5%, and 15.3% of net income for 2011, 2010, and 2009, respectively.

Cash payments for interest totaled $832 million, $789 million, and $788 million in 2011, 2010, and 2009, respectively, net of amounts capitalized of $78 million, $86 million, and $84 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 $29 million in 2011 and $32 million in 2010. Alabama Power, Gulf Power, and Mississippi Power also have discretionary authority from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2011 and 2010, such additional accruals totaled $31 million and $48 million, respectively, 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 asset. Southern Company will continue to monitor the performance of the underlying assets and to evaluate the ability of the lessee to continue to make the required lease payments. While there are strategic options that Southern Company may pursue to recover its investment in the leveraged lease, the potential impairment loss that would be incurred if there is an abandonment of the project 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 leveraged leases consists of the following at December 31:

	2011	2010
	(in millions)	
Net rentals receivable	**$ 482**	$ 475
Unearned income	**(205)**	(207)
Investment in leveraged leases	**277**	268
Deferred taxes from leveraged leases	**(238)**	(223)
Net investment in leveraged leases	**$ 39**	$ 45

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

	2011	2010	2009
		(in millions)	
Pretax leveraged lease income	**$10**	$4	$12
Income tax expense	**(4)**	(3)	(5)
Net leveraged lease income	**$ 6**	$1	$ 7

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

	2011	2010
	(in millions)	
Net rentals receivable	$ 734	$ 733
Unearned income	(362)	(377)
Investment in leveraged leases	372	356
Deferred taxes from leveraged leases	(39)	(40)
Net investment in leveraged leases	$ 333	$ 316

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

	2011	2010	2009
		(in millions)	
Pretax leveraged lease income (loss)	$15	$14	$19
Income tax benefit (expense)	(5)	(5)	(7)
Net leveraged lease income (loss)	$10	$ 9	$12

The Company terminated two international leveraged lease investments during 2009. The proceeds were used to extinguish all debt related to leveraged lease investments, a portion of which had make-whole redemption provisions. This resulted in a $17 million loss which partially offset a $26 million gain on the terminations.

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, and emissions allowances. Fuel is charged to inventory when purchased and then expensed 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 uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of Southern Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. 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, 2011, 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 not material.

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 after dividends on preferred and preference stock of subsidiaries, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

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, 2010	$ (35)	$ 7	$ (42)	$ (70)
Current period change	(9)	(4)	(28)	(41)
Balance at December 31, 2011	**$ (44)**	**$ 3**	**$ (70)**	**$(111)**

Variable Interest Entities

The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. The adoption of this accounting guidance did not result in the traditional operating companies or Southern Power consolidating any VIEs that were not already consolidated under previous guidance, nor deconsolidating any VIEs.

Certain of the traditional operating companies have established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, Southern Company and the applicable traditional operating companies are not considered the primary beneficiaries of the trusts. Therefore, the investments in these trusts are reflected as other investments, and the related loans from the trusts are reflected in long-term debt in the balance sheets.

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). No contributions to the qualified pension plan were made for the year ended December 31, 2011. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2012. 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, 2012, other postretirement trust contributions are expected to total approximately $31 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 2008 for the 2009 plan year using a discount rate of 6.75% and an annual salary increase of 3.75%.

	2011	2010	2009
Discount rate:			
Pension plans	**4.98%**	5.52%	5.93%
Other postretirement benefit plans	**4.88**	5.40	5.83
Annual salary increase	**3.84**	3.84	4.18
Long-term return on plan assets:			
Pension plans*	**8.45**	8.45	8.20
Other postretirement benefit plans	**7.39**	7.40	7.51

* Net of estimated investment management expenses of 30 basis points.

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, 2011 were as follows:

	Initial Cost Trend Rate	**Ultimate Cost Trend Rate**	**Year That Ultimate Rate Is Reached**
Pre-65	8.00%	5.00%	2019
Post-65 medical	6.00	5.00	2019
Post-65 prescription	6.00	5.00	2023

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, 2011 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$125	$(106)
Service and interest costs	7	(6)

Pension Plans

The total accumulated benefit obligation for the pension plans was $7.4 billion at December 31, 2011 and $6.7 billion at December 31, 2010. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 7,223	$ 6,758
Service cost	184	172
Interest cost	389	391
Benefits paid	(324)	(296)
Actuarial loss (gain)	607	198
Balance at end of year	8,079	7,223
Change in plan assets		
Fair value of plan assets at beginning of year	6,834	5,627
Actual return (loss) on plan assets	256	859
Employer contributions	34	644
Benefits paid	(324)	(296)
Fair value of plan assets at end of year	6,800	6,834
Accrued liability	$ (1,279)	$ (389)

At December 31, 2011, the projected benefit obligations for the qualified and non-qualified pension plans were $7.5 billion and $0.5 billion, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's pension plans consist of the following:

	2011	2010
	(in millions)	
Prepaid pension costs	$ -	$ 88
Other regulatory assets, deferred	2,614	1,749
Other current liabilities	(34)	(28)
Employee benefit obligations	(1,245)	(449)
Accumulated OCI	109	68

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2011 and 2010 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 2012.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2011:		
Accumulated OCI	$ 7	$ 102
Regulatory assets	128	2,486
Total	$ 135	$ 2,588
Balance at December 31, 2010:		
Accumulated OCI	$ 8	$ 60
Regulatory assets	159	1,590
Total	$ 167	$ 1,650
Estimated amortization in net periodic pension cost in 2012:		
Accumulated OCI	$ 1	$ 4
Regulatory assets	29	91
Total	$ 30	$ 95

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, 2011 and 2010 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2009	$ 74	$1,894
Net (gain) loss	(4)	(106)
Change in prior service costs	-	2
Reclassification adjustments:		
Amortization of prior service costs	(1)	(32)
Amortization of net gain (loss)	(1)	(9)
Total reclassification adjustments	(2)	(41)
Total change	(6)	(145)
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**

Components of net periodic pension cost were as follows:

	2011	2010	2009
		(in millions)	
Service cost	**$ 184**	$ 172	$ 146
Interest cost	**389**	391	387
Expected return on plan assets	**(607)**	(552)	(541)
Recognized net loss	**21**	10	7
Net amortization	**32**	33	35
Net periodic pension cost	**$ 19**	$ 54	$ 34

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, 2011, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2012	$ 361
2013	380
2014	398
2015	418
2016	438
2017 to 2021	2,488

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2011 and 2010 were as follows:

	2011	2010
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,752**	$ 1,759
Service cost	**21**	25
Interest cost	**92**	100
Benefits paid	**(103)**	(95)
Actuarial loss (gain)	**29**	(41)
Plan amendments	**(12)**	(2)
Retiree drug subsidy	**8**	6
Balance at end of year	**1,787**	1,752
Change in plan assets		
Fair value of plan assets at beginning of year	**802**	743
Actual return (loss) on plan assets	**4**	82
Employer contributions	**54**	66
Benefits paid	**(95)**	(89)
Fair value of plan assets at end of year	**765**	802
Accrued liability	**$ (1,022)**	$ (950)

Amounts recognized in the balance sheets at December 31, 2011 and 2010 related to the Company's other postretirement benefit plans consist of the following:

	2011	2010
	(in millions)	
Other regulatory assets, deferred	**$ 345**	$ 292
Other current liabilities	**(4)**	(1)
Employee benefit obligations	**(1,018)**	(949)
Accumulated OCI	**6**	3

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2011 and 2010 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 2012.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2011:			
Accumulated OCI	**$ -**	**$ 6**	**$ -**
Regulatory assets	**17**	**314**	**14**
Total	**$ 17**	**$320**	**$ 14**
Balance at December 31, 2010:			
Accumulated OCI	$ -	$ 3	$ -
Regulatory assets	34	233	25
Total	$ 34	$236	$ 25
Estimated amortization as net periodic postretirement benefit cost in 2012:			
Accumulated OCI	$ -	$ -	$ -
Regulatory assets	4	6	10
Total	$ 4	$ 6	$ 10

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, 2011 and 2010 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2009	$5	$374
Net (gain) loss	(2)	(60)
Change in prior service costs/transition obligation	-	(2)
Reclassification adjustments:		
Amortization of transition obligation	-	(10)
Amortization of prior service costs	-	(5)
Amortization of net gain (loss)	-	(5)
Total reclassification adjustments	-	(20)
Total change	(2)	(82)
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**

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

	2011	2010	2009
		(in millions)	
Service cost	**$ 21**	$ 25	$ 26
Interest cost	**92**	100	113
Expected return on plan assets	**(64)**	(63)	(61)
Net amortization	**20**	20	25
Net postretirement cost	**$ 69**	$ 82	$ 103

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)	
2012	$ 110	$ (10)	$100
2013	116	(12)	104
2014	122	(13)	109
2015	128	(15)	113
2016	133	(16)	117
2017 to 2021	691	(90)	601

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). In 2009, in determining the optimal asset allocation for the pension fund, the Company performed an extensive study based on projections of both assets and liabilities over a 10-year forward horizon. The primary goal of the study was to maximize plan funded status. 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, 2011 and 2010, along with the targeted mix of assets for each plan, is presented below:

	Target	**2011**	2010
Pension plan assets:			
Domestic equity	26%	**29%**	29%
International equity	25	**25**	27
Fixed income	23	**23**	22
Special situations	3	**-**	-
Real estate investments	14	**14**	13
Private equity	9	**9**	9
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	**39%**	40%
International equity	17	**18**	21
Domestic fixed income	30	**31**	29
Global fixed income	3	**4**	3
Special situations	1	**-**	-
Real estate investments	5	**5**	4
Private equity	3	**3**	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.*** An actively-managed mix of growth stocks and value stocks with both developed and emerging market exposure.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Trust-owned life insurance.*** 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, 2011 and 2010. The fair values presented are prepared in accordance with applicable accounting standards regarding fair value. 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.

Securities for which the activity is observable on an active market or traded exchange are categorized as Level 1. Fixed income securities classified as Level 2 are valued using matrix pricing, a common model utilizing observable inputs. Domestic and international equity securities classified as Level 2 consist of pooled funds where the value is not quoted on an exchange but where the value is determined using observable inputs from the market. Securities that are valued using unobservable inputs are classified as Level 3 and include investments in real estate and investments in limited partnerships. The Company invests (through the pension plan trustee) directly in the limited partnerships which then invest in various types of funds or various private entities within a fund. The fair value of the limited partnerships' investments is based on audited annual capital accounts statements which are generally prepared on a fair value basis. The Company also relies on the fact that, in most instances, the underlying assets held by the limited partnerships are reported at fair value. External investment managers typically send valuations to both the custodian and to the Company within 90 days of quarter end. The custodian reports the most recent value available and adjusts the value for cash flows since the statement date for each respective fund.

The fair values of pension plan assets as of December 31, 2011 and 2010 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 are presented in the tables below based on the nature of the investment.

	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:				
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.

	Fair Value Measurements Using			
As of December 31, 2010:	**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*	$ 1,266	$ 511	$ 1	$ 1,778
International equity*	1,277	443	-	1,720
Fixed income:				
U.S. Treasury, government, and agency bonds	-	304	-	304
Mortgage- and asset-backed securities	-	247	-	247
Corporate bonds	-	594	2	596
Pooled funds	-	201	-	201
Cash equivalents and other	2	478	-	480
Real estate investments	184	-	674	858
Private equity	-	-	638	638
Total	$ 2,729	$ 2,778	$ 1,315	$ 6,822
Liabilities:				
Derivatives	(1)	-	-	(1)
Total	$ 2,728	$ 2,778	$ 1,315	$ 6,821

*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, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
		(in millions)		
Beginning balance	$674	$638	$547	$555
Actual return on investments:				
Related to investments held at year end	72	(12)	59	67
Related to investments sold during the year	20	47	18	18
Total return on investments	92	35	77	85
Purchases, sales, and settlements	16	(91)	50	(2)
Transfers into/out of Level 3	-	-	-	-
Ending balance	$782	$582	$674	$638

The fair values of other postretirement benefit plan assets as of December 31, 2011 and 2010 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 are presented in the tables below based on the nature of the investment.

	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:				
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.

As of December 31, 2010:	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*	$ 176	$ 45	$ -	$ 221
International equity*	49	50	-	99
Fixed income:				
U.S. Treasury, government, and agency bonds	-	15	-	15
Mortgage- and asset-backed securities	-	10	-	10
Corporate bonds	-	23	-	23
Pooled funds	-	34	-	34
Cash equivalents and other	-	41	-	41
Trust-owned life insurance	-	291	-	291
Real estate investments	7	-	26	33
Private equity	-	-	23	23
Total	$ 232	$ 509	$ 49	$ 790

*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, 2011 and 2010 were as follows:

	2011		2010	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in millions)		
Beginning balance	**$26**	**$23**	$24	$24
Actual return on investments:				
Related to investments held at year end	**3**	**-**	2	1
Related to investments sold during the year	**1**	**2**	-	-
Total return on investments	**4**	**2**	2	1
Purchases, sales, and settlements	**-**	**(2)**	-	(2)
Transfers into/out of Level 3	**-**	**-**	-	-
Ending balance	**$30**	**$23**	$26	$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 2011, 2010, and 2009 were $78 million, $76 million, and $78 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 and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief and property damage allegedly caused by greenhouse gas and other emissions, 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.

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 September 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. On March 14, 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.

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. The plaintiffs appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur 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. On May 27, 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. Southern Company believes that these claims are without merit. It is not possible to predict with certainty whether the Company will incur any liability or to estimate the reasonably possible losses, if any, that the Company might incur 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, 2011 was $17 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; however, they are not expected to have a material impact on Southern Company's financial statements.

In 2008, the EPA advised Georgia Power that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices regarding this site from the EPA.

On September 29, 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 Ward Transformer Superfund site. Georgia Power does not believe it is a liable party under CERCLA based on its alleged connection to the site. As a result, on November 7, 2011, Georgia Power filed a response with the EPA indicating that Georgia Power is not willing to undertake the work set forth in the UAO because Georgia Power has sufficient cause to believe it is not a liable party. On November 22, 2011, the EPA sent Georgia Power a letter stating that the EPA does not consider Georgia Power to be in compliance with the UAO. The EPA also stated that it is considering enforcement options against Georgia Power and other UAO recipients who are not complying with the UAO.

The EPA may seek to enforce the UAO in court pursuant to its enforcement authority under CERCLA and may seek recovery of its costs in undertaking the UAO work. 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 the Ward Transformer Superfund site, in 2009, Georgia Power, along with many other parties, was sued by several existing PRPs for cost recovery for a removal action that is currently taking place. Georgia Power and numerous other defendants moved for a dismissal of these lawsuits. The court denied the dismissal of the lawsuits in March 2010 but granted Georgia Power's motion regarding the dismissal of the claim pertaining to the plaintiffs' joint and several liability.

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, it is 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 $62 million as of December 31, 2011. 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

Alabama Power and Georgia Power have contracts with the U.S., acting through the U.S. Department of Energy (DOE), that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract.

In 2007, the U.S. Court of Federal Claims awarded Georgia Power approximately $30 million, based on its ownership interests, and awarded Alabama Power 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, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit issued an order in which it affirmed the damage award to Alabama Power, but remanded the Georgia Power portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit. Georgia Power filed a motion for summary judgment related to a portion of the costs, which remains pending. On July 12, 2011, the court entered final judgment in favor of Alabama Power and awarded Alabama Power approximately $17 million. In April 2012, the award will be credited to cost of service for the benefit of customers.

In 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim) due to the government's alleged continuing breach of contract. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2011 for the second claim.

The final outcome of these matters cannot be determined at this time, but no material impact on Southern Company's net income is expected as a significant portion of any damage amounts collected from the government are expected to be returned to customers.

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 is expected to begin in sufficient time to maintain pool full-core discharge capability. 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.

Income Tax Matters

Georgia State Income Tax Credits

Georgia Power's 2005 through 2009 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. Georgia Power also filed similar claims for the years 2002 through 2004. In 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. On June 10, 2011, Georgia Power and the Georgia Department of Revenue agreed to a settlement resolving the claims. As a result, Georgia Power recorded additional tax benefits of approximately $64 million and, in accordance with the 2010 ARP, also recorded a related regulatory liability of approximately $62 million. In addition, Georgia Power recorded a reduction of approximately $23 million in related interest expense. See "Retail Regulatory Matters – Georgia Power – Other Construction" herein for additional information on the regulatory liability.

Retail Regulatory Matters

Alabama Power

Retail Rate Adjustments

On July 12, 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.

Rate RSE

Alabama Power operates under rate stabilization and equalization (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, retail rates under Rate RSE remained unchanged from 2010. The expected effect of the Alabama PSC order eliminating a tax-related adjustment, discussed above, is to increase revenues by approximately $150 million beginning in 2012. Accordingly, Alabama Power agreed to a moratorium on any increase in rates in 2012 under Rate RSE. Additionally, on December 1, 2011, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2012; earnings were within the specified return range, which precluded the need for a rate adjustment under Rate RSE. Under the terms of Rate RSE, the maximum possible increase for 2013 is 5.00%.

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 and the recovery of retail costs associated with certificated power purchase agreements (PPAs) under a rate certificated new plant (Rate CNP). Effective April 2010, Rate CNP was reduced by approximately $70 million annually, primarily due to the expiration in May 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1. Effective on April 1, 2011, Rate CNP was reduced by approximately $5 million annually. It is anticipated that no adjustment will be made to Rate CNP in 2012. As of December 31, 2011, Alabama Power had an under recovered certificated PPA balance of $6 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Alabama Power's rate certificated new plant environmental (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. Retail rates increased approximately 4.3% in January 2010 due to environmental costs. There was no adjustment to Rate CNP Environmental to recover environmental costs in 2011. On December 1, 2011, 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, which is to be recovered in the billing months of January 2012 through December 2012. On December 6, 2011, the Alabama PSC ordered that Alabama Power leave in effect for 2012 the factors associated with Alabama Power's environmental compliance costs for the year 2011. Any recoverable amounts associated with 2012 will be reflected in the 2013 filing. As of December 31, 2011, Alabama Power had an under recovered environmental clause balance of $11 million which is included in deferred 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. On September 7, 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.

Fuel Cost Recovery

Alabama Power has established fuel 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 KWH. On December 6, 2011, the Alabama PSC issued a consent order that Alabama Power leave in effect the fuel cost recovery rates which began in April 2011 for 2012. Therefore, the Rate ECR factor as of January 1, 2012 remained at 2.681 cents per KWH. Effective with billings beginning in January 2013, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2011 and 2010, Alabama Power had an under recovered fuel balance of approximately $31 million and $4 million, respectively, which is 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 discretionary authority to accrue certain additional amounts as circumstances warrant.

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.

In August 2010, the Alabama PSC approved an order enhancing the NDR that eliminated the $75 million authorized limit and allows Alabama Power to make additional accruals to the NDR. The order also 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. The structure of the monthly Rate NDR charge to customers is not altered and continues to include a component to maintain the reserve.

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 on April 27, 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 on July 12, 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 balance in the NDR for the year ended December 31, 2011 was approximately $110 million. For the year ended December 31, 2010, Alabama Power accrued an additional $48 million to the NDR, resulting in an accumulated balance of approximately $127 million. Accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as operations and maintenance expense in the statements of income.

Nuclear Outage Accounting Order

In August 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 new 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 new accounting order is 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, actual nuclear outage expenses associated with the other unit at Plant Farley will be deferred to a regulatory asset account; beginning in July 2012, these deferred costs will be 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 December 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) ECCR 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 or will be made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012, the DSM tariffs increased by $17 million;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs will increase by an estimated $122 million and $60 million, respectively, to recover the revenue requirements for the lesser of actual capital costs incurred or the amounts certified by the Georgia PSC for Plant McDonough Units 4, 5, and 6 for the period from commercial operation through December 31, 2013, which also reflects a separate settlement agreement associated with the June 30, 2011 quarterly construction monitoring report for Plant McDonough (see "Other Construction" below for additional information);
- Effective January 1, 2013, the DSM tariffs will increase by $18 million; and
- The MFF tariff will increase consistent with these adjustments.

Under the 2010 ARP, Georgia Power's 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. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. The Georgia PSC will have 90 days to rule on any such request. If approved, any ICR tariff would expire at the earlier of January 1, 2014 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2010 ARP is in effect. Georgia Power is required to file a general 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.

2011 Integrated Resource Plan Update

On August 4, 2011, Georgia Power filed an update to its Integrated Resource Plan (2011 IRP Update). The filing included Georgia Power's application to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 1, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule. Georgia Power also requested approval of expenditures for certain baghouse project preparation work at Plants Bowen, Wansley, and Hammond. However, as a result of the considerable uncertainty regarding pending federal environmental regulations, Georgia Power is continuing to defer decisions to add controls, switch fuel, or retire its remaining fleet of coal- and oil-fired generation where environmental controls have not yet been installed, representing approximately 2,600 megawatts (MWs) of capacity. Georgia Power is currently updating its economic analysis of these units based on the final Mercury and Air Toxics Standards (MATS) rule and currently expects that certain units, representing approximately 600 MWs of capacity, are more likely than others to switch fuel or be controlled in time to comply with the MATS rule. If the updated economic analysis shows more positive benefits associated with adding controls or switching fuel for more units, it is unlikely that all of the required controls could be completed by April 16, 2015, the compliance date for the MATS rule. As a result, Georgia Power cannot rely on the availability of approximately 2,000 MWs of capacity in 2015. As such, the 2011 IRP Update also includes Georgia Power's application requesting that the Georgia PSC certify the purchase of a total of 1,562 MWs of capacity beginning in 2015 from four PPAs selected through the 2015 request for proposal process. If approved, these PPA's are expected to result in additional contractual obligations of approximately $84 million in 2015, $102 million in 2016, and $1.4 billion thereafter.

In addition, Georgia Power filed a request with the Georgia PSC on August 4, 2011 for the certification of 562 MWs of certain wholesale capacity that is scheduled to be returned to retail service in 2015 and 2016 under a September 2010 agreement with the Georgia PSC. On January 30, 2012, Georgia Power entered into a stipulation with the Georgia PSC Advocacy Staff to grant the Georgia PSC an extension to the Georgia PSC's termination option date from February 1, 2012 to March 27, 2012. The Georgia PSC can exercise the termination option under specific conditions, such as changes in the cost of compliance with the EPA rules and coal unit retirement decisions.

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 Integrated Resource Plan 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 decision, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 and 2 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 and upon actual retirement has requested that the Georgia PSC approve the continued deferral and amortization of the units' remaining net carrying value. As a result of this regulatory treatment, the de-certification of Plant Branch Units 1 and 2 is not expected to have a significant impact on Southern Company's financial statements.

The Georgia PSC is expected to vote on these requests in March 2012. The ultimate outcome of these matters cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved an increase in Georgia Power's total annual billings of approximately $373 million effective April 2010, as well as a decrease of approximately $43 million effective June 1, 2011. In addition, the Georgia PSC has authorized an interim fuel rider, which allows Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million. Georgia Power currently expects to file its next case on March 30, 2012, with rates to be effective July 1, 2012.

At December 31, 2011, Georgia Power's under recovered fuel balance totaled approximately $137 million, all of which is included in current assets.

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.

Nuclear Construction

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of Georgia Power, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units 3 and 4). See Note 4 for additional information on the Owners. In 2008, Southern Nuclear filed applications with the NRC for the combined construction and operating licenses (COLs) for the new units. The NRC certified the Westinghouse Electric Company LLC's (Westinghouse) Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011. On February 9, 2012, the NRC affirmed a decision directing the NRC staff to proceed with issuance of the COLs for Plant Vogtle Units 3 and 4 in accordance with its regulations. The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Plant Vogtle Units 3 and 4, which are expected to attain commercial operation in 2016 and 2017, respectively.

On February 16, 2012, a group of four plaintiffs who had intervened in the NRC's COL proceedings for Plant Vogtle Units 3 and 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the NRC's issuance of the COLs. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's certification of the DCD. The Company intends to vigorously contest these petitions.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, the Georgia PSC voted to approve inclusion of the related construction work in progress accounts in rate base. Also in 2009, the Governor of the State of Georgia signed into law the Georgia Nuclear Energy Financing Act that allows Georgia Power to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allows Georgia Power to recover projected financing costs of approximately $1.7 billion during the construction period beginning in 2011, which reduces the projected in-service cost to approximately $4.4 billion. The Georgia PSC has ordered Georgia Power to report against this total certified cost of approximately $6.1 billion. In addition, in December 2010, the Georgia PSC approved Georgia Power's Nuclear Construction Cost Recovery (NCCR) tariff. The NCCR tariff became effective January 1, 2011 and annual adjustments are filed with the Georgia PSC on November 1 to become effective on January 1 of the following year. 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, 2011, approximately $73 million of these 2009 and 2010 costs remained in construction work in progress. At December 31, 2011, Georgia Power's portion of construction work in progress for Plant Vogtle Units 3 and 4 was $1.9 billion.

On February 10, 2012, the Georgia PSC voted to approve Georgia Power's fifth semi-annual construction monitoring report including total costs of $1.7 billion for Plant Vogtle Units 3 and 4 incurred through June 30, 2011. Georgia Power will continue to file construction monitoring reports by February 28 and August 31 of each year during the construction period.

In 2008, Georgia Power, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 MWs each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that will be subject to certain price escalations and adjustments, including fixed escalation amounts and certain 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 Consortium under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Consortium'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 Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COLs or delivery of full notice to proceed, 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.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in accordance with the Vogtle 3 and 4 Agreement in order to resolve issues arising during the course of constructing a project of this magnitude. The Consortium and Georgia Power (on behalf of the Owners) have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including potential costs associated with design changes the Consortium made to the DCD during the NRC review process and potential costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the COLs. The Consortium has not specified the amount of these costs, but such costs could be substantial, and Georgia Power expects the Consortium to seek recovery of these costs. Georgia Power is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the Vogtle 3 and 4 Agreement. Georgia Power has not agreed that the Owners have responsibility for any of these costs and, with regard to most of these costs, denies any liability and Georgia Power intends to vigorously defend itself in these matters. Georgia Power expects negotiations with the Consortium to continue over the next several months. If these costs are imposed upon the Owners, Georgia Power would seek an amendment to the certified cost of Plant Vogtle Units 3 and 4 if necessary. Additional claims by the Consortium and Georgia Power (on behalf of the Owners) may arise throughout the construction of Plant Vogtle Units 3 and 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, including legal challenges to the NRC's issuance of the COLs and certification of the DCD. Similar additional challenges at the state and federal level are expected as construction proceeds.

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

Other Construction

Georgia Power is currently constructing Plant McDonough Units 5 and 6 which are expected to be placed into service in May and November 2012, respectively. Georgia Power completed construction of Plant McDonough Unit 4 and placed it into service on December 28, 2011. On January 24, 2012, the Georgia PSC approved a stipulation agreement between Georgia Power and the Georgia PSC Public Interest Advocacy Staff to increase the certified amount for the project by 3.9% and to amortize $62 million of a regulatory liability for state income tax credits over a 21-month period beginning April 2012. See "Income Tax Matters – Georgia State Income Tax Credits" herein for additional information on this regulatory liability and "Rate Plans" above for additional information on base rate increases in 2012 and 2013 associated with the new units.

The Georgia PSC has also approved Georgia Power's quarterly construction monitoring reports, including actual project expenditures incurred, through June 30, 2011. Georgia Power will continue to file quarterly construction monitoring reports throughout the construction period.

Integrated Coal Gasification Combined Cycle

Mississippi Power is constructing a new electric generating facility located in Kemper County, Mississippi that will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs (Kemper IGCC). In May 2010, Mississippi Power filed a motion with the Mississippi PSC accepting the conditions contained in the Mississippi PSC order confirming Mississippi Power's application for a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of the Kemper IGCC. In June 2010, the Mississippi PSC issued the CPCN.

The estimated cost of the plant is $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). The Mississippi PSC's order (1) approved a construction cost cap of up to $2.88 billion (exemptions from the cost cap include the cost of the lignite mine and equipment and the carbon dioxide (CO_2) pipeline facilities), (2) provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's proposal, and (3) approved financing cost recovery on construction work in progress (CWIP) balances, which provided for the accrual of AFUDC in 2010 and 2011 and provides for the recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of CWIP allowed is (i) reduced by the amount of state and federal government construction cost incentives received by Mississippi Power in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that such CWIP allowance will benefit customers over the life of the plant). The Mississippi PSC order established periodic prudence reviews during the annual CWIP review process. Of the total costs incurred through March 2009, $46 million has been reviewed and approved by the Mississippi PSC. A decision regarding the remaining $5 million has been deferred to a later date. The timing of the review of the remaining Kemper IGCC costs is uncertain.

The Kemper IGCC plant, expected to begin commercial operation in May 2014, will use locally mined lignite (an abundant, lower heating value coal) from a mine adjacent to the plant as fuel. In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and will acquire mineral reserves located around the plant site in Kemper County. The estimated capital cost of the mine is approximately $245 million. In May 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective June 2010 through the end of the mine reclamation. On December 13, 2011, the Mississippi Department of Environmental Quality (MDEQ) approved the surface coal mining and the water pollution control permits for the mining operations operated by Liberty Fuels. On January 12, 2012, two individuals each filed a notice of appeal and a request for evidentiary hearing with the MDEQ regarding the surface coal mining and water pollution control permits.

In 2009, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $133 million of Internal Revenue Code Section 48A tax credits (Phase I) to Mississippi Power. On April 19, 2011, Mississippi Power received notification from the IRS formally certifying that the IRS allocated $279 million of Internal Revenue Code Section 48A tax credits (Phase II) to Mississippi Power. The 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 plant during operations in accordance with the recapture rules for Section 48A investment tax credits.

Through December 31, 2011, Mississippi Power received or accrued tax benefits totaling $100 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 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2011 and 2012, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be able to utilize $77 million of these tax credits until after 2012. 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.

In 2008, Mississippi Power requested that the DOE transfer the remaining funds previously granted under the CCPI2 from a cancelled integrated coal gasification combined cycle project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida, and, later in 2008, an agreement was reached to assign the remaining funds ($270 million) to the Kemper IGCC. Through December 31, 2011, Mississippi Power received grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million is expected to be received for its initial operation.

On March 10, 2011, the Sierra Club filed a lawsuit in the U.S. District Court for the District of Columbia against the DOE regarding the National Environmental Policy Act review process for the Kemper IGCC asking for a preliminary and permanent injunction on the issuance of CCPI2 funds and loan guarantees and a stay to any related construction activities based upon alleged deficiencies in the DOE's environmental impact statement. Mississippi Power intervened as a party in this lawsuit on May 18, 2011. On November 18, 2011, the U.S. District Court for the District of Columbia denied the Sierra Club's motion for preliminary injunction in the case and dismissed with prejudice the portion of the Sierra Club's claim relating to loan guarantees. On February 2, 2012, the Sierra Club filed for a voluntary dismissal with prejudice of all claims against the DOE pending in the U.S. District Court for the District of Columbia.

In March 2010, the MDEQ issued the Prevention of Significant Deterioration (PSD) air permit modification for the Kemper IGCC, which modifies the original PSD air permit issued in 2008. The Sierra Club requested a formal evidentiary hearing regarding the issuance of the modified permit. On April 4, 2011, the MDEQ Permit Board unanimously affirmed the PSD air permit. On June 30, 2011, the Sierra Club appealed the final PSD air permit issued by the MDEQ to the Chancery Court of Kemper County, Mississippi. Mississippi Power has intervened as a party in this appeal.

In June 2010, the Sierra Club filed an appeal of the Mississippi PSC's June 2010 decision to grant the CPCN for the Kemper IGCC with the Chancery Court of Harrison County, Mississippi (Chancery Court). Subsequently, in July 2010, the Sierra Club also filed an appeal directly with the Mississippi Supreme Court. In October 2010, the Mississippi Supreme Court dismissed the Sierra Club's direct appeal. On February 28, 2011, the Chancery Court issued a judgment affirming the Mississippi PSC's order authorizing the construction of the Kemper IGCC. On March 1, 2011, the Sierra Club appealed the Chancery Court's decision to the Mississippi Supreme Court.

In July 2010, Mississippi Power and South Mississippi Electric Power Association (SMEPA) entered into an Asset Purchase Agreement whereby SMEPA agreed to purchase a 17.5% undivided ownership interest in the Kemper IGCC. 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. In December 2010, Mississippi Power and SMEPA filed a joint petition with the Mississippi PSC requesting regulatory approval for SMEPA's 17.5% ownership of the Kemper IGCC.

On March 4, 2011, Mississippi Power and Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., entered into a contract pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC. On May 19, 2011, Mississippi Power and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tenrgys, LLC, entered into a contract pursuant to which Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC.

On April 27, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-A (CNP-A), a new proposed cost recovery mechanism designed specifically to recover financing costs during the construction phase of the Kemper IGCC. As part of the review of the mechanism, the Mississippi PSC will consider costs to be included as well as the allowed rate of return. CNP-A rate filings are made annually. The first filing was made on November 15, 2011 and requested an 11.66% increase in rates, or approximately $98 million annually, to recover these financing costs. If approved by the Mississippi PSC, CNP-A will remain in place thereafter until the end of the calendar year that the Kemper IGCC is placed into commercial service, which is projected to be 2014.

On August 9, 2011, Mississippi Power submitted to the Mississippi PSC a proposed rate schedule detailing Certificated New Plant-B (CNP-B) to govern rates effective from the first calendar year after the Kemper IGCC is placed into commercial service through the first seven full calendar years of its operation. Under the proposed CNP-B, Mississippi Power's allowed cost of capital would be adjusted based on certain operational performance indicators.

On June 7, 2011, 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 for the Kemper IGCC. 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.

On September 9, 2011, Mississippi Power filed a request for confirmation of the Kemper IGCC's CPCN with the Mississippi PSC authorizing the acquisition, construction, and operation of approximately 61 miles of CO_2 pipeline infrastructure at an estimated capital cost of $141 million. On January 11, 2012, the Mississippi PSC affirmed the confirmation of the Kemper IGCC's CPCN for the acquisition, construction, and operation of the CO_2 pipeline.

As of December 31, 2011, Mississippi Power had spent a total of $943 million on the Kemper IGCC, including regulatory filing costs. Of this total, $918 million was included in CWIP (which is net of $245 million of CCPI2 grant funds), $21 million was recorded in other regulatory assets, $3 million was recorded in other deferred charges and assets, and $1 million was previously expensed.

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

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with 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, 2011, 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	Amount of Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)			
Units 1 and 2	45.7%	$ 3,296	$ 1,962
Plant Hatch (nuclear)	50.1	978	545
Plant Miller (coal)			
Units 1 and 2	91.8	1,389	510
Plant Scherer (coal)			
Units 1 and 2	8.4	157	76
Plant Wansley (coal)	53.5	709	225
Rocky Mountain (pumped storage)	25.4	175	113
Intercession City (combustion turbine)	33.3	12	4
Plant Stanton (combined cycle)			
Unit A	65.0	154	27

At December 31, 2011, the portion of total construction work in progress related to Plants Miller, Scherer, and Wansley was $7 million, $63 million, and $36 million, respectively. Construction at Plants Miller, Wansley, and Scherer relates primarily to environmental projects.

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 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:

	2011	2010	2009
		(in millions)	
Federal –			
Current	**$ 57**	$ 42	$ 771
Deferred	**1,035**	898	40
	$ 1,092	940	811
State –			
Current	**8**	(54)	100
Deferred	**119**	140	(15)
	127	86	85
Total	**$ 1,219**	$ 1,026	$ 896

Net cash payments/(refunds) for income taxes in 2011, 2010, and 2009 were $(401) million, $276 million, and $975 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:

	2011	2010
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 7,882**	$ 6,833
Property basis differences	**1,256**	1,150
Leveraged lease basis differences	**277**	263
Employee benefit obligations	**499**	485
Under recovered fuel clause	**82**	179
Premium on reacquired debt	**111**	109
Regulatory assets associated with employee benefit obligations	**1,198**	814
Regulatory assets associated with asset retirement obligations	**546**	509
Other	**276**	215
Total	**12,127**	10,557
Deferred tax assets –		
Federal effect of state deferred taxes	**393**	386
State effect of federal deferred taxes	**1**	50
Employee benefit obligations	**1,594**	1,179
Over recovered fuel clause	**33**	40
Other property basis differences	**134**	119
Deferred costs	**55**	100
Cost of removal	**40**	52
Tax credit carryforward	**129**	192
Unbilled revenue	**110**	126
Other comprehensive losses	**81**	69
Asset retirement obligations	**546**	509
Other	**357**	331
Total	**3,473**	3,153
Total deferred tax liabilities, net	**8,654**	7,404
Portion included in prepaid expenses (accrued income taxes), net	**125**	117
Deferred state tax assets	**86**	91
Valuation allowance	**(56)**	(58)
Accumulated deferred income taxes	**$ 8,809**	$ 7,554

At December 31, 2011, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $879 million, which could result in net state income tax benefits of $51 million, if utilized. However, the subsidiaries have established a valuation allowance for the potential $51 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2012 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, 2011, the tax-related regulatory assets to be recovered from customers were $1.4 billion. These assets are 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. In 2010, $82 million was deferred as a regulatory asset related to the impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (together, the Acts). The Acts eliminated the deductibility of healthcare costs that are covered by federal Medicare subsidy payments. The traditional operating companies will recover and amortize the regulatory asset as approved by the state PSCs over periods not exceeding 15 years.

At December 31, 2011, the tax-related regulatory liabilities to be credited to customers were $224 million. These liabilities are 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 $19 million in 2011, $23 million in 2010, and $24 million in 2009. At December 31, 2011, 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 September 2010, the Small Business Jobs and Credit Act of 2010 (SBJCA) was signed into law. The SBJCA includes an extension of the 50% bonus depreciation for certain property acquired and placed in service in 2010 (and for certain long-term construction projects placed in service in 2011). Additionally, in December 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 construction projects to be placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term construction projects to be placed in service in 2013). The application of the bonus depreciation provisions in these acts 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:

	2011	2010	2009
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.4**	1.8	2.1
Employee stock plans dividend deduction	**(1.1)**	(1.2)	(1.4)
Non-deductible book depreciation	**0.7**	0.8	0.9
Difference in prior years' deferred and current tax rate	**(0.1)**	(0.1)	(0.1)
AFUDC-Equity	**(1.5)**	(2.2)	(2.7)
Production activities deduction	**-**	-	(0.7)
ITC basis difference	**(0.2)**	(0.4)	-
Leveraged lease termination	**-**	-	(0.9)
MC Asset Recovery	**-**	-	2.7
Donations	**-**	-	(0.4)
Other	**(0.2)**	(0.2)	(0.1)
Effective income tax rate	**35.0%**	33.5%	34.4%

Southern Company's effective tax rate is lower than or equal to the statutory rate primarily due to the employee stock plans' dividend deduction and AFUDC equity, which is not taxable.

Southern Company's 2011 effective tax rate increased from 2010 primarily due to less AFUDC equity capitalized and no Georgia state income tax credits for activity through Georgia ports available to Southern Company in 2011. Additionally, the tax benefit of the basis difference associated with investment tax credits realized during construction decreased in 2011 as compared to 2010.

Unrecognized Tax Benefits

For 2011, the total amount of unrecognized tax benefits decreased by $176 million, resulting in a balance of $120 million as of December 31, 2011.

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

	2011	2010	2009
		(in millions)	
Unrecognized tax benefits at beginning of year	**$296**	$ 199	$ 146
Tax positions from current periods	**46**	62	53
Tax positions increase from prior periods	**1**	62	12
Tax positions decrease from prior periods	**(111)**	(27)	(10)
Reductions due to settlements	**(112)**	-	-
Reductions due to expired statute of limitations	**-**	-	(2)
Balance at end of year	**$ 120**	$ 296	$ 199

The tax positions from current periods for 2011 relate primarily to a litigation settlement refund claim in 2009 relating to MC Asset Recovery, LLC, the tax accounting method change for repairs-generation assets, and other miscellaneous tax positions. See "Effective Tax Rate" herein for additional information. The tax positions decrease from prior periods and reductions due to settlements for 2011 relate to the settlement of the Georgia state tax credit litigation on June 10, 2011. See Note 3 under "Income Tax Matters – Georgia State Income Tax Credits" for additional information. In addition, the tax positions decrease from prior periods for 2011 also relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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

	2011	2010	2009
		(in millions)	
Tax positions impacting the effective tax rate	**$ 69**	$ 217	$ 199
Tax positions not impacting the effective tax rate	**51**	79	-
Balance of unrecognized tax benefits	**$120**	$ 296	$ 199

The tax positions impacting the effective tax rate for 2011 primarily relate to the production activities deduction tax position and the 2009 litigation settlement refund claim referenced above. See "Effective Tax Rate" herein for additional information. The tax positions not impacting the effective tax rate for 2011 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact. See "Tax Method of Accounting for Repairs" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

	2011	2010	2009
		(in millions)	
Interest accrued at beginning of year	**$ 29**	$ 21	$ 15
Interest reclassified due to settlements	**(24)**	-	-
Interest accrued during the year	**5**	8	6
Balance at end of year	**$ 10**	$ 29	$ 21

Southern Company classifies interest on tax uncertainties as interest expense. The interest reclassified due to settlements in 2011 is primarily associated with the Georgia state tax credit litigation settled on June 10, 2011.

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 the next 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of federal or 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 tax returns prior to 2007 and is currently auditing the federal income tax returns for 2007-2009. For tax years 2010 through 2012, Southern Company is in the Compliance Assurance Program of the IRS. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2006.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change for repair costs associated with its subsidiaries' generation, transmission, and distribution systems with the filing of the 2009 federal income tax return in September 2010. The new tax method resulted in net positive cash flow in 2010 of approximately $297 million for Southern Company on a consolidated basis. On August 19, 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine repair costs for transmission and distribution property. Based upon this guidance from the IRS, the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets has been removed. However, the IRS continues to work with the utility industry in an effort to resolve the repair costs for generation assets matter in a consistent manner for all utilities. On December 23, 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2012. 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.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

Certain of the traditional operating companies formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the applicable traditional operating company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2011 and $412 million as of December 31, 2010, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as long-term debt. Each traditional operating company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trust's payment obligations with respect to these securities. At December 31, 2011 and 2010, trust preferred securities of $200 million and $400 million, respectively, were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2011	2010
	(in millions)	
Pollution control revenue bonds	**$ -**	$ 8
Capitalized leases	**24**	23
Senior notes	**1,200**	600
Other long-term debt	**493**	670
Total	**$ 1,717**	$ 1,301

Maturities through 2016 applicable to total long-term debt are as follows: $1.7 billion in 2012; $2.1 billion in 2013; $449 million in 2014; $1.2 billion in 2015; and $1.2 billion in 2016.

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, 2011 and 2010, certain of the traditional operating companies (Georgia Power and Mississippi Power) had outstanding bank term loans totaling $690 million and $615 million, respectively. During 2011, Georgia Power entered into $250 million aggregate principal amount of long-term bank loans and $200 million aggregate principal amount of short-term bank loans. Also during 2011, Mississippi Power entered into $240 million aggregate principal amount of long-term bank loans. The proceeds of these loans were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

Subsequent to December 31, 2011, Georgia Power entered into a floating rate six-month short-term bank loan in an aggregate principal amount of $100 million bearing interest based on one-month LIBOR.

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, 2011, Georgia Power and Mississippi Power were each in compliance with their respective 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. Georgia Power and Mississippi Power are currently in compliance with all such covenants.

Senior Notes

Southern Company and its subsidiaries issued a total of $2.8 billion of senior notes in 2011. Southern Company issued $500 million, and the traditional operating companies' and Southern Power's combined issuances totaled $2.3 billion. The proceeds of these issuances were used to repay long-term and short-term indebtedness, to fund acquisitions, and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

At December 31, 2011 and 2010, Southern Company and its subsidiaries had a total of $15.9 billion and $15.2 billion, respectively, of senior notes outstanding. At December 31, 2011 and 2010, Southern Company had a total of $1.8 billion and $1.6 billion, respectively, of senior notes outstanding.

Subsequent to December 31, 2011, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

Subsequent to December 31, 2011, Alabama Power issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including Alabama Power's continuous construction program.

Subsequent to December 31, 2011, Alabama Power announced the redemption of $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047 that will occur on April 2, 2012.

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. The traditional operating companies had $3.4 billion and $3.1 billion of outstanding pollution control revenue bonds at December 31, 2011 and 2010, 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.

Subsequent to December 31, 2011, Alabama Power announced the redemption of approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008 that will occur on March 12, 2012.

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. Mississippi Power had $50 million and $100 million of such obligations outstanding at December 31, 2011 and 2010, respectively. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

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 pollution control revenue bonds with an outstanding principal amount of $194 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

On October 20, 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, 2011, committed credit arrangements with banks were as follows:

	Expires[a]						Due Within One Year		Executable Term-Loans	
Company	**2012**	**2013**	**2014**	**2016**	**Total**	**Unused**	**Term Out**	**No Term Out**	**One Year**	**Two Years**
		(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company	$ -	$ -	$ -	$1,000	$1,000	$1,000	$ -	$ -	$ -	$ -
Alabama Power	121	35	350	800	1,306	1,306	51	71	51	-
Georgia Power	-	-	250	1,500	1,750	1,745	-	-	-	-
Gulf Power	75	-	165	-	240	240	75	-	75	-
Mississippi Power	131	-	165	-	296	296	66	65	25	41
Southern Power	-	-	-	500	500	500	-	-	-	-
Other	25	25	-	-	50	50	25	-	25	-
Total	$352	$60	$930	$3,800	$5,142	$5,137	$217	$136	$176	$41

(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 approximately 1/4 of 1% or less 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, 2011, 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 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 $5.1 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, 2011 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, excluding notes payable related to other energy service contracts, were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2011:					
Commercial paper	$654	0.28%	$697	0.29%	$1,586
Short-term bank debt	200	1.18%	14	1.21%	200
Total	$854	0.49%	$711	0.32%	
December 31, 2010:					
Commercial paper	$1,295	0.32%	$690	0.29%	$1,305

(a) Average and maximum amounts are based upon daily balances during the period.

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, 2011, 2010, and 2009 in redeemable preferred stock of subsidiaries for Southern Company.

7. COMMITMENTS

Construction Program

The construction programs of the Company's subsidiaries are currently estimated to include a base level investment of $5.3 billion, $4.4 billion, and $4.3 billion for 2012, 2013, and 2014, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Also included in these estimated amounts are base level environmental expenditures to comply with existing statutes and regulations of $425 million, $405 million, and $621 million for 2012, 2013, and 2014, respectively. In addition to these base level environmental expenditures there are other potential incremental environmental compliance investments that may be necessary to comply with the EPA's final MATS rule and the proposed water and coal combustion byproducts rules. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements, to meet new 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. At December 31, 2011, significant purchase commitments were outstanding in connection with the continuous construction program, which includes new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction," "Retail Regulatory Matters – Georgia Power – Other Construction," and "Integrated Coal Gasification Combined Cycle" for additional information.

Long-Term Service Agreements

The traditional operating companies and Southern Power have entered into long-term service agreements (LTSAs) with General Electric (GE), Alstom Power, Inc., Mitsubishi Power Systems Americas, Inc., and Siemens AG for the purpose of securing maintenance support for the combined cycle and combustion turbine generating facilities owned or under construction by the subsidiaries. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each LTSA.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments under the LTSAs, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments under these LTSAs for facilities owned are currently estimated at $1.9 billion over the remaining life of the LTSAs, which are currently estimated to range up to 34 years. However, the LTSAs contain various cancellation provisions at the option of the respective traditional operating company or Southern Power, as applicable.

Georgia Power has also entered into a LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $4.5 million. The contract contains cancellation provisions at the option of Georgia Power.

Payments made under the LTSAs prior to the performance of any work are recorded as a prepayment in the balance sheets. All work performed is capitalized or charged to expense (net of any joint owner billings), as appropriate based on the nature of the work.

Limestone Commitments

As part of Southern Company's program to reduce sulfur dioxide emissions from its coal plants, the traditional operating companies have entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. Southern Company has a minimum contractual obligation of 5.6 million tons, equating to approximately $246 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) are $41 million in 2012, $42 million in 2013, $42 million in 2014, $29 million in 2015, and $22 million in 2016.

Fuel and Purchased Power Commitments

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 of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2011. Also, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity.

Total estimated minimum long-term obligations at December 31, 2011 were as follows:

	Commitments			
	Natural Gas	Coal	Nuclear Fuel	Purchased Power*
			(in millions)	
2012	$1,479	$3,266	$ 353	$ 259
2013	1,553	2,218	197	248
2014	1,196	1,336	206	281
2015	998	592	145	311
2016	937	300	92	301
2017 and thereafter	2,798	737	740	2,700
Total	$8,961	$8,449	$ 1,733	$4,100

*Certain PPAs reflected in the table are accounted for as operating leases.

Additional commitments for fuel will be required to supply the Southern Company system's future needs. Total charges for nuclear fuel included in fuel expense amounted to $215 million in 2011, $184 million in 2010, and $160 million in 2009.

Coal commitments for Mississippi Power include a minimum annual management fee of $38 million beginning in 2014 from the executed 40-year management contract with Liberty Fuels related to the Kemper IGCC.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $176 million, $188 million, and $186 million for 2011, 2010, and 2009, 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.

At December 31, 2011, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Barges & Rail Cars	Other	Total
		(in millions)	
2012	$ 79	$42	$121
2013	68	34	102
2014	53	28	81
2015	21	22	43
2016	15	17	32
2017 and thereafter	10	75	85
Total	$ 246	$218	$464

For the traditional operating companies, a majority of the barge and rail car 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 expire in 2012, 2013, 2014, 2015, 2016, and 2018 and the maximum obligations under these leases are $1 million, $39 million, $18 million, $5 million, $4 million, and $24 million, respectively. 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 earlier in this Note under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2011, Southern Company issued 21.9 million shares of common stock for $723 million through the Southern Investment Plan and employee and director stock plans. In 2010, Southern Company raised $629 million from the issuance of 19.6 million new common shares through the Southern Investment Plan and employee and director stock plans. Additionally, in 2010, Southern Company issued 4.1 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company's continuous equity offering program and received cash proceeds of $143 million, net of $1 million in fees and commissions.

Shares Reserved

At December 31, 2011, a total of 107 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 107 million shares reserved, there were 47 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2011.

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, 2011, there were 6,955 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	**2011**	2010	2009
Expected volatility	**17.5%**	17.4%	15.6%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.3%**	2.4%	1.9%
Dividend yield	**4.8%**	5.6%	5.4%
Weighted average grant-date fair value	**$3.23**	$2.23	$1.80

Southern Company's activity in the stock option program for 2011 is summarized below:

	Shares Subject To Option	Weighted Average Exercise Price
Outstanding at December 31, 2010	50,711,586	$32.48
Granted	7,100,503	38.13
Exercised	(16,800,778)	31.44
Cancelled	(54,489)	33.43
Outstanding at December 31, 2011	**40,956,822**	**$33.88**
Exercisable at December 31, 2011	**26,539,300**	**$33.54**

The number of stock options vested, and expected to vest in the future, as of December 31, 2011 was not significantly different from the number of stock options outstanding at December 31, 2011 as stated above. As of December 31, 2011, 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 $508 million and $338 million, respectively.

As of December 31, 2011, there was $7 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, 2011, 2010, and 2009, total compensation cost for stock option awards recognized in income was $22 million, $22 million, and $23 million, respectively, with the related tax benefit also recognized in income of $8 million, $9 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $155 million, $57 million, and $9 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $60 million, $22 million, and $4 million for the years ended December 31, 2011, 2010, and 2009, 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, 2011, 2010, and 2009 was $528 million, $198 million, and $19 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. Expected volatility used in the model for 2011 and 2010 was 19.2% and 20.7%, respectively. The expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate of 1.4% for 2011 and 1.4% for 2010 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 annualized dividend rate at the time of grant was $1.82 and $1.75 for 2011 and 2010, respectively. The weighted-average grant date fair value for units granted during 2010 was $30.13. Total unvested performance share units outstanding as of December 31, 2010 was 908,341. During 2011, 894,858 performance share units were granted with a weighted-average grant date fair value of $35.97. During 2011, 83,601 performance share units were forfeited resulting in 1,719,598 unvested units outstanding at December 31, 2011.

For the years ended December 31, 2011 and 2010, total compensation cost for performance share units recognized in income was $18 million and $9 million, respectively, with the related tax benefit also recognized in income of $7 million and $4 million, respectively. As of December 31, 2011, there was $29 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		
	2011	2010	2009
		(in millions)	
As reported shares	**857**	832	795
Effect of options	**7**	5	1
Diluted shares	**864**	837	796

Stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive were 0.4 million and 13.1 million at December 31, 2011 and 2010, respectively. Assuming an average stock price of $42.67 (the highest exercise price of the anti-dilutive options outstanding in 2011), the effect of options would have been immaterial for the year ended December 31, 2011. Assuming an average stock price of $38.01 (the highest exercise price of the anti-dilutive options outstanding in 2010), the effect of options would have increased by 0.8 million shares for the year ended December 31, 2010.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2011, consolidated retained earnings included $6.0 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $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, is $235 million and $237 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.

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 $43 million and $69 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, 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.

As of December 31, 2010, 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, 2010:	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	$ -	$ 10	$ -	$ 10
Interest rate derivatives	-	10	-	10
Foreign currency derivatives	-	3	-	3
Nuclear decommissioning trusts:[(a)]				
Domestic equity	604	60	-	664
U.S. Treasury and government agency securities	20	220	-	240
Municipal bonds	-	53	-	53
Corporate bonds	-	220	-	220
Mortgage and asset backed securities	-	119	-	119
Other investments	-	74	-	74
Cash equivalents and restricted cash	351	-	-	351
Other investments	9	51	19	79
Total	$984	$820	$ 19	$1,823
Liabilities:				
Energy-related derivatives	$-	$206	$-	$206
Interest rate derivatives	-	1	-	1
Total	$-	$207	$-	$207

(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 used in the 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, 2011 and 2010, 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, 2011:	*(in millions)*			
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$32	None	Daily	1 to 3 days
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
As of December 31, 2010:				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$ 65	None	Daily	1 to 3 days
Other – commingled funds	67	None	Daily	Not applicable
Trust-owned life insurance	86	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	351	None	Daily	Not applicable
Other:				
Money market funds	2	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 commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high grade money market instruments, 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, maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations having a maximum five-year final maturity with put features or floating rates with a reset date of 13 months or less. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The corporate bonds – commingled funds 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 Trust-Owned Life Insurance (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, 2011 and 2010, 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:		
2011	**$20,272**	**$22,144**
2010	$19,356	$20,073

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2).

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.

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 or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the 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, 2011, the net volume of energy-related derivative contracts for power and natural gas positions for the Southern Company system, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Power			Gas		
Net Purchased Megawatt-hours	Longest Hedge Date	Longest Non-Hedge Date	Net Purchased mmBtu*	Longest Hedge Date	Longest Non-Hedge Date
(in millions)			*(in millions)*		
1	2012	2012	189	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 9 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, 2012 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries 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, 2011, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Interest Rate Paid*	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)				*(in millions)*
Cash flow hedges of forecasted debt					
	$100	3-month LIBOR	2.22%	January 2022	$(1)
	300	3- month LIBOR	2.90%	December 2022	(17)
	300	3-month LIBOR	2.66%	April 2022	(15)
Fair value hedges of existing debt					
	350	4.15%	3-month LIBOR + 1.96% spread	May 2014	13
Total	$1,050				$(20)

* Weighted Average

For the year ended December 31, 2011, the Company had realized net gains of $5 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these gains 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.

Subsequent to December 31, 2011, Alabama Power settled $100 million of interest rate hedges related to the Series 2012A 4.10% Senior Notes issuance at a loss of approximately $1 million. The loss will be amortized to interest expense, in earnings, over 10 years.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the next 12-month period ending December 31, 2012 is $15 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. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2011, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2011
	(in millions)			*(in millions)*
Fair value hedges of firm commitments				
	EUR9.2	1.371 Dollars per Euro*	Various through March 2014	$(1)
Derivatives not designated as hedges				
	EUR18.1	1.317 Dollars per Euro*	N/A	-
Total				$(1)

* Weighted Average

During the year ended December 31, 2011, certain fair value hedges were de-designated. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company.

Derivative Financial Statement Presentation and Amounts

At December 31, 2011 and 2010, 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**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$9**	$4	Liabilities from risk management activities	**$163**	$145
	Other deferred charges and assets	**5**	3	Other deferred credits and liabilities	**72**	55
Total derivatives designated as hedging instruments for regulatory purposes		**$14**	$7		**$235**	$200
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$-**	$-	Liabilities from risk management activities	**$1**	$1
Interest rate derivatives:	Other current assets	**6**	6	Liabilities from risk management activities	**33**	1
	Other deferred charges and assets	**7**	4	Other deferred credits and liabilities	**-**	-
Foreign currency derivatives:	Other current assets	**-**	2	Liabilities from risk management activities	**1**	-
	Other deferred charges and assets	**-**	1	Other deferred credits and liabilities	**-**	-
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$13**	$13		**$35**	$2
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$-**	$2	Liabilities from risk management activities	**$9**	$5
	Other deferred charges and assets	**-**	1	Other deferred credits and liabilities	**-**	-
Foreign currency derivatives	Other current assets	**2**	-	Liabilities from risk management activities	**2**	-
Total derivatives not designated as hedging instruments		**$2**	$3		**$11**	$5
Total		**$29**	$23		**$281**	$207

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

At December 31, 2011 and 2010, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2011**	2010	**Balance Sheet Location**	**2011**	2010
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$(163)**	$(145)	Other regulatory liabilities, current	**$9**	$4
	Other regulatory assets, deferred	**(72)**	(55)	Other regulatory liabilities, deferred	**5**	3
Total energy-related derivative gains (losses)		**$(235)**	$(200)		**$14**	$7

For the year ended December 31, 2011, the pre-tax gains from interest rate derivatives designated as fair value hedging instruments on Southern Company's statement of income were $3 million. This amount was offset by changes in the fair value of the hedged debt.

For the year ended December 31, 2011, the pre-tax losses from foreign currency derivatives designated as fair value hedging instruments on Southern Company's statement of income, which include pre-tax losses arising from de-designated hedges prior to de-designation, were $4 million. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2011**	2010	2009	**Statements of Income Location**	**2011**	2010	2009
		(in millions)				*(in millions)*	
Energy-related derivatives	**$ -**	$ 1	$ (2)	Fuel	**$ -**	$ -	$ -
Interest rate derivatives	**(28)**	(3)	(5)	Interest expense, net of amounts capitalized	**(14)**	(25)	(46)
Foreign currency derivatives	**-**	1	-	Other operations and maintenance	**-**	1	-
				Other income (expense), net	**(1)**	-	-
Total	**$(28)**	$(1)	$ (7)		**$ (15)**	$ (24)	$ (46)

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

For the years ended December 31, 2011, 2010, and 2009, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was as follows:

Derivatives not Designated as Hedging Instruments	Unrealized Gain (Loss) Recognized in Income			
		Amount		
Derivative Category	**Statements of Income Location**	**2011**	2010	2009
			(in millions)	
Energy-related derivatives:	Wholesale revenues	**$ 2**	$ (2)	$ 5
	Fuel	**(9)**	1	(6)
	Purchased power	**1**	(1)	(4)
Total		**$ (6)**	$ (2)	$(5)

For the year ended December 31, 2011, the pre-tax losses from foreign currency derivatives not designated as hedging instruments were recorded as a regulatory asset and were not material to the Company.

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, 2011, the fair value of derivative liabilities with contingent features was $36 million.

At December 31, 2011, 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 $36 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. Southern Power's revenues from sales to the traditional operating companies were $359 million, $371 million, and $544 million in 2011, 2010, and 2009, 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)			
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
2009							
Operating revenues	$15,304	$ 947	$(609)	$15,642	$ 165	$(64)	$15,743
Depreciation and amortization	1,378	98	-	1,476	27	-	1,503
Interest income	21	-	-	21	3	(1)	23
Interest expense	749	85	-	834	71	-	905
Income taxes	902	86	-	988	(92)	-	896
Segment net income (loss)*	1,679	156	-	1,835	(193)	1	1,643
Total assets	48,403	3,043	(143)	51,303	1,223	(480)	52,046
Gross property additions	4,568	331	-	4,899	14	-	4,913

*After dividends on preferred and preference stock of subsidiaries

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2011	**$15,071**	**$1,905**	**$611**	**$17,587**
2010	$14,791	$1,994	$589	$17,374
2009	13,307	1,802	533	15,642

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2011 and 2010 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 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**
March 2010	$4,157	$ 922	$495	$0.60	$0.4375	$33.73	$30.85
June 2010	4,208	951	510	0.62	0.4550	35.45	32.04
September 2010	5,320	1,459	817	0.98	0.4550	37.73	33.00
December 2010	3,771	470	153	0.18	0.4550	38.62	37.10

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2007 through 2011
Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions)	**$17,657**	$17,456	$15,743	$17,127	$15,353
Total Assets (in millions)	**$59,267**	$55,032	$52,046	$48,347	$45,789
Gross Property Additions (in millions)	**$4,853**	$4,443	$4,913	$4,122	$3,658
Return on Average Common Equity (percent)	**13.04**	12.71	11.67	13.57	14.60
Cash Dividends Paid Per Share of Common Stock	**$1.8725**	$1.8025	$1.7325	$1.6625	$1.595
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	**$2,203**	$1,975	$1,643	$1,742	$1,734
Earnings Per Share --					
Basic	**$2.57**	$2.37	$2.07	$2.26	$2.29
Diluted	**2.55**	2.36	2.06	2.25	2.28
Capitalization (in millions):					
Common stock equity	**$ 17,578**	$ 16,202	$14,878	$ 13,276	$ 12,385
Preferred and preference stock of subsidiaries	**707**	707	707	707	707
Redeemable preferred stock of subsidiaries	**375**	375	375	375	373
Long-term debt	**18,647**	18,154	18,131	16,816	14,143
Total (excluding amounts due within one year)	**$37,307**	$35,438	$34,091	$31,174	$27,608
Capitalization Ratios (percent):					
Common stock equity	**47.1**	45.7	43.6	42.6	44.9
Preferred and preference stock of subsidiaries	**1.9**	2.0	2.1	2.3	2.6
Redeemable preferred stock of subsidiaries	**1.0**	1.1	1.1	1.2	1.3
Long-term debt	**50.0**	51.2	53.2	53.9	51.2
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$20.32**	$19.21	$18.15	$17.08	$16.23
Market price per share:					
High	**$46.69**	$38.62	$37.62	$40.60	$39.35
Low	**35.73**	30.85	26.48	29.82	33.16
Close (year-end)	**46.29**	38.23	33.32	37.00	38.75
Market-to-book ratio (year-end) (percent)	**227.8**	199.0	183.6	216.6	238.8
Price-earnings ratio (year-end) (times)	**18.0**	16.1	16.1	16.4	16.9
Dividends paid (in millions)	**$1,601**	$1,496	$1,369	$1,279	$1,204
Dividend yield (year-end) (percent)	**4.0**	4.7	5.2	4.5	4.1
Dividend payout ratio (percent)	**72.7**	75.7	83.3	73.5	69.5
Shares outstanding (in thousands):					
Average	**856,898**	832,189	794,795	771,039	756,350
Year-end	**865,125**	843,340	819,647	777,192	763,104
Stockholders of record (year-end)	**155,198**	160,426*	92,799	97,324	102,903
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,809**	3,813	3,798	3,785	3,756
Commercial	**579**	580	580	594	600
Industrial	**15**	15	15	15	15
Other	**9**	9	9	8	6
Total	**4,412**	4,417	4,402	4,402	4,377
Employees (year-end)	**26,377**	25,940	26,112	27,276	26,472

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2007 through 2011
Southern Company and Subsidiary Companies 2011 Annual Report

	2011	2010	2009	2008	2007
Operating Revenues (in millions):					
Residential	**$ 6,268**	$ 6,319	$ 5,481	$5,476	$5,045
Commercial	**5,384**	5,252	4,901	5,018	4,467
Industrial	**3,287**	3,097	2,806	3,445	3,020
Other	**132**	123	119	116	107
Total retail	**15,071**	14,791	13,307	14,055	12,639
Wholesale	**1,905**	1,994	1,802	2,400	1,988
Total revenues from sales of electricity	**16,976**	16,785	15,109	16,455	14,627
Other revenues	**681**	671	634	672	726
Total	**$17,657**	$17,456	$15,743	$17,127	$15,353
Kilowatt-Hour Sales (in millions):					
Residential	**53,341**	57,798	51,690	52,262	53,326
Commercial	**53,855**	55,492	53,526	54,427	54,665
Industrial	**51,570**	49,984	46,422	52,636	54,662
Other	**936**	943	953	934	962
Total retail	**159,702**	164,217	152,591	160,259	163,615
Wholesale sales	**30,345**	32,570	33,503	39,368	40,745
Total	**190,047**	196,787	186,094	199,627	204,360
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.75**	10.93	10.60	10.48	9.46
Commercial	**10.00**	9.46	9.16	9.22	8.17
Industrial	**6.37**	6.20	6.04	6.54	5.52
Total retail	**9.44**	9.01	8.72	8.77	7.72
Wholesale	**6.28**	6.12	5.38	6.10	4.88
Total sales	**8.93**	8.53	8.12	8.24	7.16
Average Annual Kilowatt-Hour Use Per Residential Customer	**13,997**	15,176	13,607	13,844	14,263
Average Annual Revenue Per Residential Customer	**$1,645**	$1,659	$1,443	$1,451	$1,349
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**43,555**	42,961	42,932	42,607	41,948
Maximum Peak-Hour Demand (megawatts):					
Winter	**34,617**	35,593	33,519	32,604	31,189
Summer	**36,956**	36,321	34,471	37,166	38,777
System Reserve Margin (at peak) (percent)	**19.2**	23.3	26.4	15.3	11.2
Annual Load Factor (percent)	**59.0**	62.2	60.6	58.7	57.6
Plant Availability (percent):					
Fossil-steam	**88.1**	91.4	91.3	90.5	90.5
Nuclear	**93.0**	92.1	90.1	91.3	90.8
Source of Energy Supply (percent):					
Coal	**48.7**	55.0	54.7	64.0	67.1
Nuclear	**15.0**	14.1	14.9	14.0	13.4
Hydro	**2.1**	2.5	3.9	1.4	0.9
Oil and gas	**28.0**	23.7	22.5	15.4	15.0
Purchased power	**6.2**	4.7	4.0	5.2	3.6
Total	**100.0**	100.0	100.0	100.0	100.0

MANAGEMENT COUNCIL

1. Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Fanning, 55, 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, 57, 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, 55, joined the Company as a Residential Sales Representative with Gulf Power in 1979. He has held his current position since January 2011. Previously, Bowers served as Chief Financial Officer for the Company. He also served as 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. Mark A. Crosswhite
President and Chief Executive Officer of Gulf Power
Crosswhite, 49, joined the Company in 2004 as Senior Vice President and General Counsel for Southern Company Generation. He has held his current position since January 2011. He also served as 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.

5. Edward Day, VI
President and Chief Executive Officer of Mississippi Power
Day, 51, 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.

6. G. Edison Holland, Jr.
Executive Vice President, General Counsel,
and Corporate Secretary
Holland, 59, 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 2001. Previously, he was President and Chief Executive Officer of Savannah Electric and Vice President of Power Generation and Transmission at Gulf Power.

7. Stephen E. Kuczynski
Chairman, President and Chief Executive Officer of Southern Nuclear
Kuczynski, 49, joined the Company in 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.

8. Charles D. McCrary
Executive Vice President
President and Chief Executive Officer of Alabama Power
McCrary, 60, 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.

9. Susan N. Story
Executive Vice President
President and Chief Executive Officer, Southern Company Services, Inc.
Story, 52, joined the Company as a Nuclear Power Plant Engineer in 1982. She has held her current position since January 2011. Previously, Story was President and Chief Executive Officer of Gulf Power and Executive Vice President of Engineering and Construction Services for Southern Company Generation and Energy Marketing. She has held executive and management positions in the areas of supply chain management, real estate, corporate services, and human resources.

10. Anthony J. Topazi
Executive Vice President and
Chief Operating Officer
Topazi, 61, joined the Company as a Cooperative Education Student with Alabama Power in 1969. He assumed his current position in August 2010. Topazi previously served as President and Chief Executive Officer of Mississippi Power, Executive Vice President for Southern Company Generation and Energy Marketing, and Senior Vice President of Southern Power. He also has held various positions at Alabama Power, including Western Division Vice President and Birmingham Division Vice President.

11. Christopher C. Womack
Executive Vice President and
President, External Affairs
Womack, 54, joined the Company in 1988 as a Governmental Affairs Representative for Alabama Power. He has held his current position since 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 14 through 20 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. In January 2012, Computershare completed its acquisition of the Company's former transfer agent, dividend-paying agent, investment plan administrator, and registrar, Bank of New York Mellon Shareowner Services. If you have questions concerning your registered the Company shareowner account, please contact:

By Mail
The Southern Company
c/o Computershare Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252-8035

By Courier
The Southern Company
c/o Computershare Shareowner Services
480 Washington Blvd.
Jersey City, NJ 07310

By Phone
9 a.m. to 7 p.m. ET
Monday through Friday
800-554-7626
(Automated voice response system
24 hours/day, 7 days/week)

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 self assigned PIN. The internet address is www.bnymellon.com/shareowner/equityaccess. 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 2011 is taxable. The Board of Directors sets the record and payment dates for quarterly dividends. A dividend of 47.25 cents per share was paid in March 2012. For the remainder of 2012, projected record dates are May 7, August 6, and November 5. Projected payment dates for dividends declared during the remainder of 2012 are June 6, September 6, and December 6.

Auditors

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

During 2011, 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, 2011, Southern Company had 155,198 stockholders of record.

SOUTHERN COMPANY

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