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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

OR

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

For the Transition Period From ______________ to ______________

Commission File No. 000-53908

Oglethorpe Power Corporation

(An Electric Membership Corporation)
(Exact name of registrant as specified in its charter)

Georgia (State or other jurisdiction of incorporation or organization)	**58-1211925** (I.R.S. employer identification no.)
2100 East Exchange Place **Tucker, Georgia** (Address of principal executive offices)	**30084-5336** (Zip Code)
Registrant's telephone number, including area code:	**(770) 270-7600**
Securities registered pursuant to Section 12(b) of the Act:	**None**
Securities registered pursuant to Section 12(g) of the Act:	**Series 2009 B Bonds**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. **Yes** ___ **No** ✓

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. **Yes** ___ **No** ✓

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes** ✓ **No** ___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **Yes** ✓ **No** ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [✓]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ___ Accelerated filer ___ Non-accelerated filer ✓ (Do not check if a smaller reporting company) Smaller reporting company ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ___ **No** ✓

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. **The Registrant is a membership corporation and has no authorized or outstanding equity securities.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. **The Registrant is a membership corporation and has no authorized or outstanding equity securities.**

Documents Incorporated by Reference: **None**

OGLETHORPE POWER CORPORATION

2011 FORM 10-K ANNUAL REPORT

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ITEM 1. BUSINESS

OGLETHORPE POWER CORPORATION

General

We are a Georgia electric membership corporation (an EMC) incorporated in 1974 and headquartered in metropolitan Atlanta. We are owned by our 39 retail electric distribution cooperative members. Our principal business is providing wholesale electric power to our members. As with cooperatives generally, we operate on a not-for-profit basis. We are the largest electric cooperative in the United States in terms of assets, kilowatt-hour sales to members and, through our members, consumers served. We are also the second largest power supplier in the state of Georgia. We have 216 employees.

Our members are local consumer-owned distribution cooperatives that provide retail electric service on a not-for-profit basis. In general, our members' customer base consists of residential, commercial and industrial consumers within specific geographic areas. Our members serve approximately 1.8 million electric consumers (meters) representing approximately 4.1 million people. See ''OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES.''

Our mailing address is 2100 East Exchange Place, Tucker, Georgia 30084-5336, and telephone number is (770) 270-7600. We maintain a website at *www.opc.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available on this website as soon as reasonably practicable after this material is filed with the Securities and Exchange Commission. Information contained on our website is not incorporated by reference into and should not be considered to be part of this annual report on Form 10-K.

Cooperative Principles

Cooperatives like Oglethorpe are business organizations owned by their members, which are also either their wholesale or retail customers. As not-for-profit organizations, cooperatives are intended to provide services to their members at the lowest possible cost, in part by eliminating the need to produce profits or a return on equity. Cooperatives may make sales to non-members, the effect of which is generally to reduce costs to members. Today, cooperatives operate throughout the United States in such diverse areas as utilities, agriculture, irrigation, insurance and credit.

All cooperatives are based on similar business principles and legal foundations. Generally, an electric cooperative designs its rates to recover its cost-of-service and to collect a reasonable amount of revenues in excess of expenses, which constitutes margins. The margins increase patronage capital, which is the equity component of a cooperative's capitalization. These margins are considered capital contributions (that is, equity) from the members and are held for the accounts of the members and returned to them when the board of directors of the cooperative deems it prudent to do so. The timing and amount of any actual return of capital to the members depends on the financial goals of the cooperative and the cooperative's loan and security agreements.

Power Supply Business

We provide wholesale electric service to our members for the majority of their aggregate power requirements primarily from our generation assets but also with power purchased from other power suppliers. We provide substantially all of this service pursuant to long-term, take-or-pay wholesale power contracts, with a small amount supplied to seven of our members through a power sale agreement we acquired in conjunction with the acquisition of the Hawk Road Energy Facility in 2009. The wholesale power contracts obligate our members jointly and severally to pay rates sufficient for us to recover all the costs of owning and operating our power supply business, including the payment of principal and interest on our indebtedness and to yield a minimum 1.10 margins for interest ratio under our first mortgage indenture. Our members satisfy all of their power requirements above their purchase obligations to us with purchases from other suppliers. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

We have interests in 31 operating generating units, fueled by nuclear, coal, gas, oil and water. See "OUR POWER SUPPLY RESOURCES'' and ''PROPERTIES – Generating Facilities."

In 2011, two of our members, Cobb EMC and Jackson EMC, accounted for 12.5% and 10.9% of our total revenues, respectively. Each of our other members accounted for less than 10% of our total revenues in 2011.

Wholesale Power Contracts

The wholesale power contracts we have with each member are substantially similar and extend through December 31, 2050 and continue thereafter until terminated by three years' written notice by us or the respective member. Under the wholesale power contracts, each member is unconditionally obligated, on an express "take-or-pay" basis, for a fixed percentage of the capacity costs of each of our generation resources and purchased power resources with a term greater than one year. Each wholesale power contract specifically provides that the member must make payments whether or not power is delivered and whether or not a plant has been sold or is otherwise unavailable. We are obligated to use our reasonable best efforts to operate, maintain and manage our resources in accordance with prudent utility practices.

We have assigned fixed percentage capacity cost responsibilities to our members for all of our generation and purchased power resources, although not all members participate in all resources. For any future resource, we will assign fixed percentage capacity cost responsibilities only to members choosing to participate in that resource. The wholesale power contracts provide that each member is jointly and severally responsible for all costs and expenses of all existing generation and purchased power resources, as well as for any approved future resources, whether or not that member has elected to participate in the future resource. For resources so approved in which less than all members participate, costs are shared first among the participating members, and if all participating members default, each non-participating member is expressly obligated to pay a proportionate share of the default.

To acquire future resources, we are required to obtain the approval of 75% of the members of our board of directors, 75% of our members and members representing 75% of our patronage capital. We can make certain resource modifications if approved by more than 50% of the members of our board of directors and 50% of our members.

Under the wholesale power contracts, we are not obligated to provide all of our members' capacity and energy requirements. Individual members must satisfy all of their requirements above their purchase obligations from us from other suppliers, unless we and our members agree that we will supply additional capacity and associated energy, subject to the approval requirements described above. In 2011, we supplied energy that accounted for approximately 52% of the retail energy requirements of our members. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Under the wholesale power contracts, each member must establish rates and conduct its business in a manner that will enable the member to pay (i) to us when due, all amounts payable by the member under its wholesale power contract and (ii) any and all other amounts payable from, or which might constitute a charge or a lien upon, the revenues and receipts derived from the member's electric system, including all operation and maintenance expenses and the principal of, premium, if any, and interest on all indebtedness related to the member's electric system.

New Business Model Member Agreement

The New Business Model Member Agreement that we have with our members requires member approval for us to undertake certain activities. The agreement does not limit our ability to own, manage, control and operate our resources or perform our functions under the wholesale power contracts.

We may not provide services unrelated to our resources or our functions under the wholesale power contracts if these services would require us to incur indebtedness, provide a guarantee or make any loan or investment, unless approved by 75% of the members of our board of directors, 75% of our members, and members representing 75% of our patronage capital. We may provide any other unrelated service to a member so long as (i) doing so would not create a conflict of interest with respect to other members, (ii) the service is being provided to all members or (iii) the service has received the three 75% approvals described above.

Electric Rates

Each member is required to pay us for capacity and energy we furnish under its wholesale power contract in accordance with rates we establish. We review our rates at intervals that we deem appropriate but are required to do so at least once every year. We are required to revise our rates as necessary so that the revenues derived from our rates, together with our revenues from all other sources, will be sufficient to pay all of the costs of our system, including the payment of principal and interest on our indebtedness, to provide for reasonable reserves and to meet all financial requirements.

Our principal financial requirements are contained in the Indenture, dated as of March 1, 1997, from us to U.S. Bank National Association, as trustee (successor to SunTrust Bank), as amended and supplemented, referred to herein as the first mortgage indenture. Under the first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates which are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. Margins for interest ratio is the ratio of margins for interest to total interest charges for a given period. Margins for interest is the sum of:

- our net margins (which includes our revenues subject to refund at a later date but excludes provisions for (i) non-recurring charges to income, including the non-recoverability of assets or expenses, except to the extent we determine to recover these charges in rates, and (ii) refunds of revenues we collected or accrued subject to refund), plus
- interest charges, whether capitalized or expensed, on all indebtedness secured under the first mortgage indenture or by a lien equal or prior to the lien of the first mortgage indenture, including amortization of debt discount or premium on issuance, but excluding interest charges on indebtedness assumed by Georgia Transmission Corporation (which, as described below, was formed in 1997 to operate the transmission business we previously owned), plus
- any amount included in net margins for accruals for federal or state income taxes imposed on income after deduction of interest expense.

Margins for interest takes into account any item of net margin, loss, gain or expenditure of any of our affiliates or subsidiaries only if we have received the net margins or gains as a dividend or other distribution from such affiliate or subsidiary or if we have made a payment with respect to the losses or expenditures.

The formulary rate we established in the rate schedule to the wholesale power contracts employs a rate methodology under which all categories of costs are specifically separated as components of the formula to determine our revenue requirements. The rate schedule also implements the responsibility for fixed costs assigned to each member based on each member's fixed percentage capacity cost responsibilities for all of our generation and purchased power resources. The monthly charges for capacity and other non-energy charges are based on our annual budget. These capacity and other non-energy charges may be adjusted by our board of directors, if necessary, during the year through an adjustment to the annual budget. Energy charges reflect the pass-through of actual energy costs, including fuel costs, variable operations and maintenance costs and purchased energy costs. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Summary of Cooperative Operations – *Rates and Regulation.*"

The rate schedule formula also includes a prior period adjustment mechanism designed to ensure that we achieve the minimum 1.10 margins for interest ratio. Amounts, if any, by which we fall short of the minimum 1.10 margins for interest ratio are accrued as of December 31 of the applicable year and collected from our members from April through December of the following year. The rate schedule formula is intended to provide for the collection of revenues which, together with revenues from all other sources, are equal to all costs and expenses we recorded, plus amounts necessary to achieve at least the minimum 1.10 margins for interest ratio.

To enhance margin coverage during the period of generation facility construction and acquisition, our board of directors approved a budget for 2009 to achieve a 1.12 margins for interest ratio, and budgets for 2010, 2011 and 2012 to achieve a 1.14 margins for interest ratio, each above the minimum 1.10 ratio required by the first mortgage indenture. As our construction and acquisition program evolves, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

Under the first mortgage indenture and related loan contract with the Rural Utilities Service, adjustments to our rates to reflect changes in our budgets are generally not subject to Rural Utilities Service approval. Changes to the rate schedule under the wholesale power contracts are generally subject to Rural Utilities Service approval. Our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

Relationship with Smarr EMC

Smarr EMC is a Georgia electric membership corporation owned by 36 of our 39 members. Smarr EMC owns two combustion turbine facilities with aggregate capacity of 709 megawatts. We provide operations, financial and management services for Smarr EMC. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Relationship with Georgia Transmission Corporation

We and our 39 members are members of Georgia Transmission Corporation (An Electric Membership Corporation), which was formed in 1997 to own and operate the transmission business we previously owned. Georgia Transmission provides transmission services to its members for delivery of its members' power purchases from us and other power suppliers. Georgia Transmission also provides transmission services to third parties. We have entered into an agreement with Georgia Transmission to provide transmission services for third party transactions and for service to our own facilities.

In 1997, Georgia Transmission assumed certain indebtedness associated with pollution control bonds originally issued on our behalf. If Georgia Transmission fails to satisfy its obligations under this debt, we remain liable for any unsatisfied amounts. Georgia Transmission plans to refund all of this existing assumed indebtedness by April 2012. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Off-Balance Sheet Arrangements.*"

Georgia Transmission has rights in the integrated transmission system, which consists of transmission facilities owned by Georgia Transmission, Georgia Power Company, the Municipal Electric Authority of Georgia and the City of Dalton, Georgia. Through agreements, common access to the combined facilities that compose the integrated transmission system enables the owners to use their combined resources to make deliveries to or for their respective consumers, to provide transmission service to third parties and to make off-system purchases and sales. The integrated transmission system was established in order to obtain the benefits of a coordinated development of the parties' transmission facilities and to make it unnecessary for any party to construct duplicative facilities.

Relationship with Georgia System Operations Corporation

We, Georgia Transmission and 38 of our 39 members are members of Georgia System Operations Corporation, which was formed in 1997 to own and operate the system operations business we previously owned. Georgia System Operations operates the system control center and currently provides Georgia Transmission and us with system operations services and administrative support services. We have contracted with Georgia System Operations to schedule and dispatch our resources. We also purchase from Georgia System Operations services that it purchases from Georgia Power under the control area compact, which we co-signed with Georgia System Operations. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Members' Relationship with Georgia Transmission and Georgia System Operations." Georgia System Operations provides support services to us in the areas of accounting, auditing, communications, human resources, facility management, telecommunications and information technology at cost.

As of December 31, 2011, we had approximately $6.0 million of loans outstanding to Georgia System Operations, primarily for the purpose of financing capital expenditures. Georgia System Operations has an additional $4.0 million that can be drawn under one of its loans with us.

Georgia Transmission has contracted with Georgia System Operations to provide certain transmission system operation services including reliability monitoring, switching operations, and the real-time management of the transmission system.

Relationship with Rural Utilities Service

Historically, federal loan programs administered by the Rural Utilities Service, an agency of the United States Department of Agriculture, have provided the principal source of financing for electric cooperatives. Loans guaranteed by the Rural Utilities Service and made by the Federal Financing Bank have been a major source of funding for us. However, the availability and magnitude of Rural Utilities Service-direct and guaranteed loan funds are subject to annual federal budget appropriations and thus cannot be assured. Currently, Rural Utilities Service-direct and guaranteed loan funds are subject to increased uncertainty because of budgetary and political pressures faced by Congress. The President's budget proposal for fiscal year 2013 provides for $6.1 billion in loans – a reduction of less than 10% from 2012 levels. Not more than $2 billion could be made available for environmental improvements to fossil-fueled generation that would reduce emissions, with the remaining funding limited to renewable energy, transmission, distribution and carbon-capture projects on generation facilities, and low emission peaking units affiliated with energy facilities that produce electricity from solar, wind and other intermittent sources of energy. Although Congress has historically rejected proposals to dramatically curtail the Rural Utilities Service loan program, there can be no assurance that it will continue to do so. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service-direct and guaranteed loans that may be available to us in the future.

We have a loan contract with the Rural Utilities Service in connection with the first mortgage indenture. Under the loan contract, the Rural Utilities Service has approval rights over certain significant actions and arrangements, including, without limitation,

- significant additions to or dispositions of system assets,
- significant power purchase and sale contracts,
- changes to the wholesale power contracts and the rate schedule contained in the wholesale power contracts,
- changes to plant ownership and operating agreements,
- amounts of short-term debt outstanding exceeding 30% of our total utility plant through December 31, 2014 and 15% of total capitalization thereafter, and
- in limited circumstances, issuance of additional secured and unsecured debt.

The first mortgage indenture constitutes a lien on substantially all of the tangible and certain intangible property we own.

Relationship with Georgia Power Company

Our relationship with Georgia Power is a significant factor in several aspects of our business. Georgia Power is responsible for the construction and operation of all of our co-owned generating facilities, except the Rocky Mountain Pumped Storage Hydroelectric Facility, on behalf of itself as a co-owner and as agent for the other co-owners. Georgia Power supplies services to us and Georgia System Operations to support the scheduling and dispatch of our resources, including off-system transactions. Georgia Power and our members are competitors in the State of Georgia for electric service to any new customer that has a choice of supplier under the Georgia Territorial Electric Service Act, which was enacted in 1973, commonly known as the Georgia Territorial Act. For further information regarding the agreements between Georgia Power and us and our members' relationships with Georgia Power, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Service Area and Competition" and "PROPERTIES – Fuel Supply," "– Co-Owners of Plants – *Georgia Power Company*" and "– The Plant Agreements."

Competition

Under current Georgia law, our members generally have the exclusive right to provide retail electric service in their respective territories. Since 1973, however, the Georgia Territorial Act has permitted limited competition among electric utilities located in Georgia for sales of electricity to certain large commercial or industrial customers. The owner of any new facility may receive electric service from the power supplier of its choice if the facility is located outside of municipal limits and has a connected load upon initial full operation of 900 kilowatts or more. Our members are actively engaged in competition with other retail electric suppliers for these new commercial and industrial loads. While the competition for 900-kilowatt loads represents only limited competition in Georgia, this competition has given our members the opportunity to develop resources and strategies to prepare for a more competitive market.

Some states have implemented varying forms of retail competition among power suppliers. No legislation related to retail competition has yet been enacted in

Georgia, and no bill is currently pending in the Georgia legislature which would amend the Georgia Territorial Act or otherwise affect the exclusive right of our members to supply power to their current service territories. The Georgia Public Service Commission does not have the authority under Georgia law to order retail competition or amend the Georgia Territorial Act. We cannot predict at this time the outcome of various developments that may lead to increased competition in the electric utility industry or the effect of any developments on us or our members.

We routinely consider, along with our members, a wide array of other potential actions to meet future power supply needs, to reduce costs, to reduce risks of the competitive generation business and to respond to competition. Alternatives that could be considered include:

- power marketing arrangements or other alliance arrangements;
- adjusting the mix of ownership and purchase arrangements used to meet power supply requirements;
- construction or acquisition of power supply resources, whether owned by us or by other entities;
- use of power purchase contracts to meet power supply requirements, and whether to use short, medium or long-term contracts, or a mix of terms;
- participation in future power supply resources developed by others, whether by ownership or long-term purchase commitment;
- whether disposition of existing assets or asset classes would be advisable;
- maturity extensions of existing indebtedness;
- potential prepayment of debt;
- various responses to the proliferation of non-core services offered by electric utilities;
- mergers or other combinations among distributors or power suppliers; and
- other regulatory and business changes that may affect relative values of generation classes or have impacts on the electric industry.

We will continue to consider industry trends and developments, but cannot predict at this time the results of these matters or any action we or our members might take based on these industry trends and developments. These considerations necessarily would take account of and are subject to legal, regulatory and contractual (including financing and plant co-ownership arrangements) considerations.

Regulation of greenhouse gas emissions has the potential to affect energy suppliers, including us and our competitors, differently, depending not only on the relative greenhouse gas emissions from a supplier's sources, but also on the nature of the regulation. For example, certain legislative proposals have included various credits that would ultimately be phased out to offset the initial economic impact of regulation. Our greenhouse gas emissions are significant, but we also have generation sources that emit no greenhouse gases. Some of our competitors use sources that emit proportionately more greenhouse gases, while the sources of some competitors emit less. Further, third-party suppliers to our members rely on generation sources that emit greenhouse gases. The contracts with these third-party suppliers would determine the extent to which our members would be affected by regulation of the greenhouse gas emissions of their suppliers. We believe our and our members' diverse portfolios of generation facilities, including the diversity of third-party suppliers, along with potential credits that could be available to us or our members under certain legislative proposals, would mitigate the impact, if any, on our and our members' competitiveness resulting from these legislative proposals, if enacted. See "ENVIRONMENTAL AND OTHER REGULATIONS – Carbon Dioxide Emission and Climate Change – *Pending Legislation*" and "Risk Factors".

Many members are also providing or considering proposals to provide non-traditional products and services such as telecommunications and other services. In 2002, the Georgia legislature enacted legislation empowering the Georgia Public Service Commission to authorize member affiliates to market natural gas. The Georgia Public Service Commission is required to condition any authorization on terms designed to ensure that cross-subsidizations do not occur between the electricity services of a member and the gas activities of its gas affiliates.

Depending on the nature of the generation business in Georgia, there could be reasons for the members to separate their physical distribution business from their energy business, or otherwise restructure their current businesses to operate more effectively.

Further, a member's power supply planning may include consideration of assignment of its rights and obligations under its wholesale power contract to another member or a third party. We have existing provisions for wholesale power contract assignment, as well as provisions for a member to withdraw and concurrently to assign its rights and obligations under its wholesale power contract. Assignments upon withdrawal require the assignee to have certain published credit ratings and to assume all of the withdrawing member's obligations under its wholesale power contract with us, and must be approved by our board of directors. Assignments without withdrawal are governed by the wholesale power contract and must be approved by both our board of directors and the Rural Utilities Service.

From time to time, individual members may be approached by parties indicating an interest in purchasing their systems. A member generally must obtain our approval before it may consolidate or merge with any person or reorganize or change the form of its business organization from an electric membership corporation or sell, transfer, lease or otherwise dispose of all or substantially all of its assets to any person, whether in a single transaction or series of transactions. A member may enter into such a transaction without our approval if specified conditions are satisfied, including, but not limited to, an agreement by the transferee, satisfactory to us, to assume the obligations of the member under the wholesale power contract, and certifications of accountants as to certain specified financial requirements of the transferee. The wholesale power contracts also provide that a member may not dissolve, liquidate or otherwise wind up its affairs without our approval.

Seasonal Variations

Our members' demand for energy is influenced by seasonal weather conditions. Historically, our peak sales have occurred during the months of June through August. Even so, summer sales historically have been lower when weather conditions are milder, and higher when weather conditions are more extreme. While changing weather patterns, whether resulting from greenhouse gas emissions or otherwise, could, under certain circumstances, alter seasonal weather patterns, predictions of future changes in weather patterns are inherently speculative, and we can not make accurate conclusions about seasonality related to changes in weather patterns. Energy revenues track energy costs as they are incurred and also fluctuate month to month. Capacity revenues reflect the recovery of our fixed costs, which do not vary significantly from month to month; therefore, capacity charges are billed and capacity revenues are recognized in substantially equal monthly amounts.

OUR POWER SUPPLY RESOURCES

General

We supply capacity and energy to our members for a portion of their requirements from a combination of our generating assets and power purchased from other suppliers. In 2011, we supplied approximately 52% of the retail energy requirements of our members.

Generating Plants

We have interests in 31 operating generating units. The Municipal Electric Authority of Georgia, the City of Dalton and Georgia Power also have interests in nine of these units − at Plants Hatch, Vogtle, Wansley and Scherer. Georgia Power serves as operating agent for these units. Georgia Power also has an interest in Rocky Mountain, which we operate.

See "PROPERTIES" for a description of our generating facilities, fuel supply and the co-ownership arrangements and Note 4 to Notes to Consolidated Financial Statements regarding the power purchase agreement with Doyle I, LLC that we account for as a capital lease. Also see "PROPERTIES – The Plant Agreements – *Doyle.*"

Power Purchase and Sale Arrangements

Power Purchases

We currently have no material power purchase agreements. We purchase small amounts of capacity and energy from "qualifying facilities" under the Public Utility Regulatory Policies Act of 1978. Under a waiver order from the Federal Energy Regulatory Commission, we historically made all purchases the members would have otherwise been required to make under the Public Utility Regulatory Policies Act and we were relieved of our obligation to sell certain services to "qualifying facilities" so long as the members make those sales. In 2011, our purchases from such qualifying facilities provided less than 0.1% of the energy we supplied to our members. Under their wholesale power contracts, the members may now make such purchases instead of us.

Power Sales

In conjunction with our acquisition of Hawk Road in 2009, we accepted assignment of a power purchase and sale agreement pursuant to which we sell 500 megawatts of capacity and associated energy to seven of our members, with a term through December 31, 2015.

Our acquisition of Murray I and II LLC in 2011 included a power purchase and sale agreement with Georgia Power for the entire output of Murray Unit No. 1 that terminates May 31, 2012. Prior to our members' use of Murray, generally planned beginning in 2016, the output of both units will be marketed to third parties in order to reduce the net cost of this facility to our members.

Other Power System Arrangements

We have interchange, transmission and/or short-term capacity and energy purchase or sale agreements with approximately 42 utilities, power marketers and other power suppliers. The agreements provide variously for the purchase and/or sale of capacity and energy and/or for the purchase of transmission service. We are currently using only about one-half of these agreements, primarily to facilitate the short-term management of our resource portfolio.

Future Power Resources

Plant Vogtle Units No. 3 and No. 4

We are participating in 30% of the costs of the construction of two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4, scheduled for commercial operation in 2016 and 2017, respectively.

In April 2008, Georgia Power, for itself and as agent for us, The Municipal Electric Authority of Georgia and the City of Dalton (the Owners), signed an Engineering, Procurement and Construction Contract with Westinghouse Electric Company, LLC and Stone & Webster, Inc. (the Consortium). Pursuant to the contract, the Consortium will supply and construct two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology, with the exception of certain owner supplied items. Under the contract, the Owners will pay a purchase price that is subject to certain price escalation and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders and performance bonuses.

Each Owner is severally, not jointly, liable to the Consortium based on its ownership share. The contract includes certain liquidated damages upon the Consortium's failure to comply with schedule and performance guarantees, as well as certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability for those liquidated damages and for warranty claims is subject to a cap. The obligations of Westinghouse and Stone & Webster are guaranteed by their parent companies Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, that Owner would be required to provide a letter of credit or other credit enhancement to the Consortium. In addition, the Owners may terminate the contract 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 contract under certain circumstances, including delays in receipt of the combined construction permits and operating licenses, certain Owner suspension or delays of work, action by a governmental authority to stop work permanently, certain breaches of the contract by the Owners, Owner insolvency and certain other events.

The Owners and the Consortium have established both informal and formal dispute resolution procedures in order to resolve issues arising during the course of constructing a project of this magnitude. Southern Nuclear Operating Company, on behalf of the Owners, has successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expects 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 AP1000 Design Control Document (DCD) during the Nuclear Regulatory Commission 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 combined construction permits and operating licenses. The Consortium has not specified the amount of these costs, but such costs could be substantial, and the Owners expect the Consortium to seek recovery of these costs. Southern Nuclear, on behalf of the Owners, is engaged in discussions with the Consortium regarding the allocation of responsibility for these costs under the terms of the agreement. Southern Nuclear 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 the Owners intend to vigorously defend themselves in these matters. Southern Nuclear expects negotiations with the Consortium to continue over the next several months. Additional claims by the Consortium and Southern Nuclear, on behalf of the Owners, may arise throughout the construction of Vogtle Units No. 3 and No. 4.

Our rights and obligations with respect to these additional units are contained in an Ownership Participation Agreement, the Plant Vogtle Operating Agreement (amended to include Units No. 3 and No. 4), and the Nuclear Managing Board Agreement (amended to include Units No. 3 and No. 4). The Ownership Participation Agreement is similar to the agreement that covers Units No. 1 and No. 2.

In March 2008, Southern Nuclear, on behalf of the Owners, filed an application for combined construction permits and operating licenses for two 1,100 megawatt units, using the Westinghouse AP1000 technology.

The Nuclear Regulatory Commission certified the AP1000 design effective December 30, 2011. On February 10, 2012, the Nuclear Regulatory Commission issued combined licenses for Vogtle Units No. 3 and No. 4. Receipt of these licenses allows full construction to begin on Vogtle Units No. 3 and No. 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 Nuclear Regulatory Commission's license proceedings for Vogtle Units No. 3 and No. 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 Nuclear Regulatory Commission's issuance of the license. 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 Nuclear Regulatory Commission's certification of the DCD. The Owners intend to vigorously contest these petitions.

For a discussion regarding the events at the Fukushima Daiichi nuclear plant in Japan and the potential effects on the construction of Plant Vogtle Units No. 3 and No. 4, see "ENVIRONMENTAL AND OTHER REGULATION – Nuclear Regulation" and "RISK FACTORS."

Our estimated total costs for the new units, including allowance for funds used during construction, are approximately $4.2 billion. As of December 31, 2011, our share of construction work in progress for this project was approximately $1.3 billion. We submitted a loan application to the Department of Energy seeking partial funding for these proposed nuclear units and have been offered a conditional term sheet for 70% of the eligible project costs not to exceed $3.057 billion. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Capital Requirements – Capital Expenditures*" and "– *Financing Activities.*"

There are pending technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4, including the legal challenges to the Nuclear Regulatory Commission issuance of the combined licenses and certification of the DCD as described above. Similar additional challenges at the state and federal level are expected as construction proceeds.

Biomass Plant

Our members had subscribed for a 100 megawatt biomass-fueled generating plant. We acquired a site in Warren County, Georgia, conducted preliminary engineering work and environmental analyses, and requested proposals for major equipment and for an engineering, procurement and construction contract. However, due primarily to regulatory and legislative uncertainty, we have deferred this plant. We continue to monitor regulatory and legislative developments related to biomass electricity generation.

Other Future Power Resources

From time to time, we may assist our members in investigating potential new power supply resources, after compliance with the terms of the New Business Model Member Agreement See "OGLETHORPE POWER CORPORATION – New Business Model Member Agreement." Our members have given general approval for the future development of certain quantities of gas-fired plants that may be planned for commercial operation prior to December 31, 2016, subject to future member subscriptions for specific projects no later than December 31, 2012. Based on informal indications of member interest, we do not expect member subscriptions for projects to exceed 250 megawatts, if any are subscribed at all.

OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES

Member Demand and Energy Requirements

Our members are listed below and include 39 of the 42 electric distribution cooperatives in the State of Georgia.

Altamaha EMC
Amicalola EMC
Canoochee EMC
Carroll EMC
Central Georgia EMC
Coastal EMC (d/b/a Coastal Electric Cooperative)
Cobb EMC
Colquitt EMC
Coweta-Fayette EMC
Diverse Power Incorporated, an EMC
Excelsior EMC
Flint EMC (d/b/a Flint Energies)
Grady EMC
GreyStone Power Corporation, an EMC
Habersham EMC
Hart EMC
Irwin EMC
Jackson EMC
Jefferson Energy Cooperative, an EMC
Little Ocmulgee EMC
Middle Georgia EMC
Mitchell EMC
Ocmulgee EMC
Oconee EMC
Okefenoke Rural EMC
Pataula EMC
Planters EMC
Rayle EMC
Satilla Rural EMC
Sawnee EMC
Slash Pine EMC
Snapping Shoals EMC
Southern Rivers Energy, Inc., an EMC
Sumter EMC
Three Notch EMC
Tri-County EMC
Upson EMC
Walton EMC
Washington EMC

In December 2009, Flint EMC became our 39th member. Flint is participating in certain future generation resources, but we are not currently supplying any of Flint's capacity or energy requirements. All of the historical member statistics in this report include Flint.

Our members serve approximately 1.8 million electric consumers (meters) representing approximately 4.1 million people. Our members serve a region covering approximately 38,000 square miles, which is approximately 65% of the land area in the State of Georgia, encompassing 151 of the State's 159 counties. Historically, our members' sales by customer class have been approximately two-thirds to residential consumers and slightly less than one-third to commercial and industrial consumers. Our members are the principal suppliers for the power needs of rural Georgia. While our members do not serve any major cities, portions of their service territories are in close proximity to urban areas and have experienced substantial growth over the years due to the expansion of urban areas, including metropolitan Atlanta, into suburban areas and the growth of suburban areas into neighboring rural areas. Each year we file with one of our quarterly reports on Form 10-Q an exhibit containing financial and statistical information for our 39 members for the most recent three year period.

The following table shows the aggregate peak demand and energy requirements of our members for the years 2009 through 2011, and also shows the amount of their energy requirements that we supplied. From 2009 through 2011, demand and energy requirements of the members increased at an average annual compound rate of 3.1% and 1.6%, respectively.

	Member Demand (MW)	Member Energy Requirements (MWh)	
	Total(1)	Total(2)	Supplied by Oglethorpe(3)
2009	8,470	36,793,085	20,191,657
2010	8,990	40,169,810	22,644,790
2011	8,998	38,000,846	19,574,145

(1) System peak hour demand of our members measured at our members' delivery points (net of system losses), adjusted to include requirements served by us and member resources, to the extent known by us, behind the delivery points.

(2) Retail requirements served by our and member resources, adjusted to include requirements served by resources, to the extent known by us, behind the delivery points. See "– Member Power Supply Resources."

(3) Includes energy supplied to members for resale at wholesale. We supplied none of Flint's energy requirements during this period and do not currently anticipate supplying any until 2016.

Service Area and Competition

The Georgia Territorial Act regulates the service rights of all retail electric suppliers in the State of Georgia. Pursuant to the Georgia Territorial Act, the Georgia Public Service Commission assigned substantially all areas in the State to specified retail suppliers. With limited exceptions, our members have the exclusive right to provide retail electric service in their respective territories, which are predominately outside of the municipal limits existing at the time the Georgia Territorial Act was enacted in 1973. The principal exception to this rule of exclusivity is that electric suppliers may compete for most new retail loads of 900 kilowatts or greater. The Georgia Public Service Commission may reassign territory only if it determines that an electric supplier has breached the tenets of public convenience and necessity. The Georgia Public Service Commission may transfer service for specific premises only if: (i) it determines, after joint application of electric suppliers and proper notice and hearing, that the public convenience and necessity require a transfer of service from one electric supplier to another; or (ii) it finds, after proper notice and hearing, that an electric supplier's service to a premise is not adequate or dependable or that its rates, charges, service rules and regulations unreasonably discriminate in favor of or against the consumer utilizing the premise and the electric utility is unwilling or unable to comply with an order from the Georgia Public Service Commission regarding the service.

Since 1973, the Georgia Territorial Act has allowed limited competition among electric utilities in Georgia by allowing the owner of any new facility located outside of municipal limits and having a connected load upon initial full operation of 900 kilowatts or greater to receive electric service from the retail supplier of its choice. Our members, with our support, are actively engaged in competition with other retail electric suppliers for these new commercial and industrial loads. The number of commercial and industrial loads served by our members continues to increase annually. While the competition for 900-kilowatt loads represents only limited competition in Georgia, this competition has given our members and us the opportunity to develop resources and strategies to operate in an increasingly competitive market.

For further information regarding member competitive activities, see "OGLETHORPE POWER CORPORATION – Competition."

Cooperative Structure

Our members are cooperatives that operate their systems on a not-for-profit basis. Accumulated margins derived after payment of operating expenses and provision for depreciation constitute patronage capital of the consumers of our members. Refunds of accumulated patronage capital to the individual consumers may be made from time to time subject to limitations contained in mortgages between the members and the Rural Utilities Service or loan documents with other lenders. The Rural Utilities Service mortgages generally prohibit these distributions unless (i) after any of these distributions, the member's total equity will equal at least 30% of its total assets or (ii) distributions do not exceed 25% of the margins and patronage capital received by the member in the preceding year and equity is at least 20%. See "– Members' Relationship with the Rural Utilities Service."

We are a membership corporation, and our members are not our subsidiaries. Except with respect to the obligations of our members under each member's wholesale power contract with us and our rights under these contracts to receive payment for power and energy supplied, we have no legal interest in (including through a pledge or otherwise), or obligations in respect of, any of the assets, liabilities, equity, revenues or margins of our members. See "OGLETHORPE POWER CORPORATION – Wholesale Power Contracts." The assets and revenues of our members are, however, pledged under their respective mortgages with the Rural Utilities Service or loan documents with other lenders.

We depend on the revenue we receive from our members pursuant to the wholesale power contracts to cover the costs of the operation of our power supply business and satisfy our debt service obligations.

Rate Regulation of Members

Through provisions in the loan documents securing loans to the members, the Rural Utilities Service exercises control and supervision over the rates for the sale of power of our members that borrow from it. The Rural Utilities Service mortgage indentures of these members require them to design rates with a view to maintaining an average times interest earned ratio and an average debt service coverage ratio of not less than 1.25 and an operating times interest earned ratio and an operating debt service coverage ratio of not less than

1.10, in each case for the two highest out of every three successive years.

The Georgia Electric Membership Corporation Act, under which each of the members was formed, requires the members to operate on a not-for-profit basis and to set rates at levels that are sufficient to recover their costs and to provide for reasonable reserves. The setting of rates by the members is not subject to approval by any federal or state agency or authority other than the Rural Utilities Service, but the Georgia Territorial Act prohibits the members from unreasonable discrimination in the setting of rates, charges, service rules or regulations and requires the members to obtain Georgia Public Service Commission approval of long-term borrowings.

Cobb EMC, Diverse Power Incorporated, an EMC, Mitchell EMC, Oconee EMC, Snapping Shoals EMC and Walton EMC have repaid all of their Rural Utilities Service indebtedness and are no longer Rural Utilities Service borrowers. Each of these members now has a rate covenant with its current lender. Other members may also pursue this option. To the extent that a member which is not an Rural Utilities Service borrower engages in wholesale sales or sales of transmission service in interstate commerce, it would, in certain circumstances, be subject to regulation by the Federal Energy Regulatory Commission under the Federal Power Act.

Members' Relationship with the Rural Utilities Service

Through provisions in the loan documents securing loans to the members, the Rural Utilities Service also exercises control and supervision over the members that borrow from it in such areas as accounting, other borrowings, construction and acquisition of facilities, and the purchase and sale of power.

Historically, federal loan programs providing direct and guaranteed loans from the Rural Utilities Service to electric cooperatives have been a major source of funding for the members. Under the current Rural Utilities Service loan programs, electric distribution borrowers are eligible for loans made by the Federal Financing Bank or other lenders and guaranteed by the Rural Utilities Service. Certain borrowers with either low consumer density or higher than average rates and lower than average consumer income are eligible for special loans that bear interest at an annual rate of 5%. However, the availability and magnitude of Rural Utilities Service direct and guaranteed loan funds is subject to annual federal budget appropriations and thus cannot be assured. Currently, the availability of Rural Utilities Service loan funds is subject to increased uncertainty because of budgetary pressures faced by Congress.

The President's budget proposal for fiscal year 2013 proposes to reduce funding by less than 10% from 2012 levels for the Rural Utilities Service electric program. The proposed funding would be available only for transmission, distribution, renewable energy and carbon capture projects for generation and certain environmental improvements. We cannot predict the amount or cost of Rural Utilities Service direct and guaranteed loans that may be available to the members in the future.

Members' Relationships with Georgia Transmission and Georgia System Operations

Georgia Transmission provides transmission services to our members for delivery of our members' power purchases from us and other power suppliers. Georgia Transmission and the members have entered into member transmission service agreements under which Georgia Transmission provides transmission service to the members pursuant to a transmission tariff. The member transmission service agreements have a minimum term for network service until December 31, 2060. The members' transmission service agreements include certain elections for load growth above 1995 requirements, with notice to Georgia Transmission, to be served by others. These agreements also provide that if a member elects to purchase a part of its network service elsewhere, it must pay appropriate stranded costs to protect the other members from any rate increase that they could otherwise occur. Under the member transmission service agreements, members have the right to design, construct and own new distribution substations.

Georgia System Operations has contracts with each of its members, including Georgia Transmission and us, to provide to them the services that it in turn purchases from Georgia Power under the Control Area Compact, which we co-signed with Georgia System Operations. Georgia System Operations also provides operation services for the benefit of our members through agreements with us, including dispatch of our resources and other power supply resources owned by the members.

For information about our relationship with Georgia System Operations, see "OGLETHORPE POWER CORPORATION – Relationship with Georgia System Operations Corporation."

Member Power Supply Resources

Oglethorpe Power Corporation

In 2011, we supplied approximately 52% of the retail energy requirements of our members. Pursuant to the wholesale power contracts, we supply each member, other than Flint, energy from our generation resources based on its fixed percentage capacity cost responsibility, which are take-or-pay obligations. See "OGLETHORPE POWER CORPORATION – Wholesale Power Contracts." Additionally, effective May 2009, we assumed a power purchase and sale agreement with seven of our members in connection with our acquisition of Hawk Road. See "OUR POWER SUPPLY RESOURCES – Power Purchase and Sale Arrangements – *Power Sales.*" Our members satisfied all of their requirements above their purchase obligations to us with purchases from other suppliers as described below.

Contracts with Southeastern Power Administration

Our members purchase hydroelectric power from the Southeastern Power Administration, or SEPA, under contracts that extend until 2016 and thereafter until terminated by two years' written notice by SEPA or the respective member. In 2011, the aggregate SEPA allocation to the members was 618 megawatts plus associated energy. The availability of energy under these contracts is significantly affected by hydrologic conditions, including lengthy droughts. Each member must schedule its energy allocation, and each member, other than Flint, has designated us to perform this function. Pursuant to a separate agreement, we schedule, through Georgia System Operations, our members' SEPA power deliveries. Further, each member may be required, if certain conditions are met, to contribute funds for capital improvements for Corps of Engineers projects from which its allocation is derived in order to retain the allocation.

Smarr EMC

The 36 members participating in the facilities owned by Smarr EMC purchase the output of those facilities pursuant to long-term, take-or-pay power purchase agreements. Smarr EMC owns Smarr Energy Facility, a two-unit, 217 megawatt gas-fired combustion turbine facility, and Sewell Creek Energy Facility, a four-unit, 492 megawatt gas-fired combustion turbine facility. Smarr Energy Facility began commercial operation in June 1999 and Sewell Creek Energy Facility began commercial operation in June 2000. See "OGLETHORPE POWER CORPORATION – Relationship with Smarr EMC."

Green Power EMC

Our members are also members of Green Power Electric Membership Corporation, a power supply cooperative specializing in the purchase of renewable energy sources for its members. The members purchase small quantities of energy from Green Power EMC. As of January 1, 2012, we began supplying management services to Green Power EMC.

Georgia Energy Cooperative

Fifteen of our members are members of Georgia Energy Cooperative, An Electric Membership Corporation, which owns a 100 megawatt gas turbine facility, in addition to providing other services to its members.

Georgia Power Block Purchase

Thirty members have entered into power supply contracts with Georgia Power under which they purchase an aggregate of 750 megawatts of capacity and associated energy. These contracts expire December 31, 2014.

Other Member Resources

Our members obtain their remaining power supply requirements from various sources. Thirty-two members have entered into contracts with third parties for some or all of their incremental power requirements, with remaining terms ranging from 4 to 20 years. The other members use a portfolio of power purchase contracts to meet their requirements.

We have not undertaken to obtain a complete list of member power supply resources. Any of our members may have committed or may commit to additional power supply obligations not described above.

For information about members' activities relating to their power supply planning, see "OGLETHORPE POWER CORPORATION – Competition" and "OUR POWER SUPPLY RESOURCES – Future Power Resources." In addition to future power supply resources that we may construct or acquire for our members, the members will likely also continue to acquire future resources from other suppliers, including suppliers that may be owned by members.

ENVIRONMENTAL AND OTHER REGULATION

General

As is typical for electric utilities, we are subject to various federal, state and local air and water quality requirements which, among other things, regulate emissions of pollutants into the air and discharges of other pollutants into the waters of the United States. We are also subject to federal, state and local waste disposal requirements that regulate the manner of transportation, storage and disposal of various types of waste.

In general, environmental requirements are becoming increasingly stringent. Although we have installed or are in the process of installing environmental control systems at our plants to ensure continued compliance with existing requirements, including systems to reduce emissions of sulfur dioxide, oxides of nitrogen and mercury at Plants Scherer and Wansley, new requirements could be imposed in the future. Such requirements may substantially increase the cost of electric service, by requiring changes in the design or operation of existing facilities, the purchase of emission allowances, or changes or delays in the location, design, construction or operation of new facilities. Failure to comply with these requirements could result in the imposition of civil and criminal penalties as well as the complete shutdown of individual generating units not in compliance. Certain of our debt instruments require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current or future environmental laws or regulations. Should we fail to be in compliance with these requirements, it would constitute a default under those debt instruments. Although it is our intent to comply with current and future regulations, we cannot provide assurance that we will always be in compliance with applicable current and future regulations.

Our capital expenditures and operating costs will continue to reflect compliance with environmental standards. For further discussion of expected future capital expenditures to comply with environmental requirements and regulations, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Capital Requirements – Capital Expenditures.*"

Air Quality

Environmental concerns of the public, the scientific community and Congress have resulted in the enactment of legislation that has had and will continue to have a significant impact on the electric utility industry. The most significant environmental legislation applicable to us is the Clean Air Act, which regulates emissions of sulfur dioxide, nitrogen oxides, particulate matter, greenhouse gases and other pollutants from affected electric utility units, including the coal-fired units at Plants Wansley and Scherer. The following appear to be the most significant Clean Air Act related actions.

National Ambient Air Quality Standards and Nonattainment Updates. The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six common air pollutants, five of which are of principal importance to utilities – particulate matter, ground-level ozone, carbon monoxide, sulfur dioxide and nitrogen dioxide – and, of less significance to utilities, lead. Many of the NAAQS have recently been revised or are in the process of being revised to make them more stringent. The final revised standards are being litigated. More stringent NAAQS could cause certain areas in Georgia to be reclassified as "nonattainment," which may require additional emissions reductions from power plants we own or co-own there and in surrounding areas, to bring those areas into "attainment." Although the co-owned coal-fired plants already have control systems installed or being installed for these pollutants, the costs of any additional pollution control equipment that could be required due to new or revised NAAQS cannot be determined at this time.

Clean Air Interstate Rule and the Cross State Air Pollution Rule. EPA finalized the Clean Air Interstate Rule (CAIR) in 2005 for ozone and fine particulate matter, requiring emissions reductions in sulfur dioxide and nitrogen oxides in most eastern states, including Georgia, through a market-based cap and trade program. In August 2011, EPA finalized the Cross State Air Pollution Rule (CSAPR) to replace the CAIR. Similar to CAIR, the CSAPR was to impose cap and trade programs for sulfur dioxide and nitrogen oxides emissions on fossil fuel-fired electric generating units located in covered states, including Georgia. In Georgia, a sulfur dioxide emissions cap was to be imposed in two phases, with the first phase beginning in 2012 and the second, more stringent phase in 2014. Reductions of nitrogen oxides emissions were to be implemented using two caps, one for annual and one for ozone season emissions, and in two phases, with the first phase for both caps beginning in 2012 and the second, more stringent phase, beginning in 2014. This rule could have required the purchase of emission allowances or limiting operations at Plant Scherer during off-peak periods or a combination of the two in 2012. However, in December of 2011, the U.S. Court of Appeals for the D.C. Circuit stayed the CSAPR, pending judicial review of the rule and ordered that CAIR remain in place. The Court has ordered that briefing on the CSAPR be concluded by mid-March and that oral argument be held in mid-April of 2012, making reinstatement of the CSAPR for the 2012 compliance year unlikely. While the outcome of these CSAPR proceedings may affect the future operations of our co-owned units at Plants Scherer and Wansley, given that additional emission control systems will be coming on line beginning in 2013 at Plant Scherer, we do not expect that the allowance purchases and/or operating limitations described above will be necessary in 2013 and beyond.

Mercury and Air Toxics Standards and State Mercury Rule. In response to EPA's determination that regulation of hazardous air pollutants from fossil fuel-fired electric utility steam generating units is appropriate and necessary in late 2000 and subsequent litigation, EPA finalized its Mercury and Air Toxics Standards (MATS) rule in December of 2011, establishing maximum achievable control technology limits for certain hazardous air pollutants for coal and oil-fired electric generating units. For coal units, the rule sets stringent emission limits to control various hazardous air pollutants – mercury, non-mercury metals and acid gases – and work practice standards to control organics and dioxins. These regulations could require the installation of additional emission control technologies. Affected generating units will have until April 16, 2015 to comply; extensions for one or two years are possible under limited circumstances. Challenges to the MATS have already been filed.

Georgia's current mercury rules include a ''multi-pollutant rule'' that requires operation of the existing controls for Plant Wansley and existing and planned controls for Plant Scherer as follows – selective catalytic reduction systems and scrubbers at Plant Wansley; and activated carbon injection and baghouses, scrubbers and selective catalytic reduction at Plant Scherer. Emission control projects are already underway at Plant Scherer and are expected to be completed by 2014 and to cost approximately \$920 million, which includes approximately \$616 million spent to date. EPA's MATS will likely require further controls at Plants Wansley and/or Scherer for compliance, including but not limited to the potential installation of activated carbon injection and baghouses at Plant Wansley. If required, baghouses at Plant Wansley would likely be installed from 2012 through early 2016 at an approximate cost to us of \$150 million. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Condition – *Capital Requirements – Capital Expenditures.*''

New Source Review. In November 1999, the United States Department of Justice, on behalf of EPA, filed lawsuits against Georgia Power and some of its affiliates, as well as other utilities. The lawsuits allege violations of the new source review provisions and the new source performance standards of the Clean Air Act at Plant Scherer Unit Nos. 3 and 4 as well as other facilities. We are not currently named in the lawsuits and we do not have an ownership interest in the named Plant Scherer units. However, we can give no assurance that units in which we have an interest will not be affected by this or a related lawsuit in the future. The case has remained administratively closed since the spring of 2001. The resolution of this matter is highly uncertain at this time, as is any responsibility for a share of any penalties and capital costs that might be required to remedy violations at the co-owned facilities.

Rulemakings that began in 2009 now impose new source review requirements on greenhouse gases, including carbon dioxide, under the Prevention of Significant Deterioration (PSD) preconstruction permitting program. As a result, PSD review for major stationary sources of greenhouse gases was triggered on January 2, 2011. See ''Carbon Dioxide Emissions and Climate Change – *Executive Branch Action*.''

Air Quality Summary. We believe that the controls being designed and/or installed at Plants Wansley and Scherer will meet the requirements of the rules described above. However, because (i) several of these proposed or final Clean Air Act regulations could require control of the same emissions, (ii) the compliance requirements remain uncertain, (iii) litigation challenging some or all of these rules is likely, and (iv) specific control technologies affect multiple emissions, we cannot determine the aggregate effect of these or future regulations.

Depending on the final outcome of these developments, and the implementation approach selected by EPA and the State of Georgia with respect to environmental regulations, we may have to incur significant capital expenditures and increased operating expenses at Plants Wansley and/or Scherer.

Compliance with the requirements of the Clean Air Act may also require increased capital or operating expenses on the part of Georgia Power. Any increases in Georgia Power's capital or operating expenses may cause an increase in the cost of power purchased from Georgia Power. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Georgia Power Block Purchase.*"

Carbon Dioxide Emissions and Climate Change

Efforts to limit emissions of carbon dioxide from power plants continue. Such limitations on emissions could originate in the Congress, the executive branch or the courts.

Emissions of carbon dioxide from our plants totaled approximately 11.7 million short tons in 2011. In 2011, 34% of our generation, excluding pumped storage, came from our interests in the coal-fired units at Plants Scherer and Wansley, which would be the most impacted by any greenhouse gas-related legislation or regulation, while another 24% came from our gas-fired facilities which would also be somewhat impacted but not to the same extent as the coal-fired plants. The remaining generation (42%) came from our interest in the nuclear Plants Vogtle and Hatch which would likely not be impacted by any climate change regulation or legislation aimed at reducing greenhouse gas emissions.

Pending Legislation. There is little reason to believe that the 112th Congress will pass any legislation pertaining to the direct regulation of greenhouse gases, including carbon dioxide. In addition, the creation and passage of any energy legislation that could include a national renewable electricity standard does not appear likely. We cannot predict at this time whether any legislation will be passed that would result in the regulation of greenhouse gas emissions from our power plants, directly or indirectly, nor can we predict the impacts from any relevant federal legislation.

Executive Branch Action. The U.S. Supreme Court ruled in 2007 that certain greenhouse gases, including carbon dioxide, are pollutants which EPA has the authority to regulate under the Clean Air Act if EPA concludes regulation is needed to protect public health or welfare. EPA determined that regulation was needed and issued a series of rules that establish a three-step schedule for application of the Clean Air Act PSD and Title V programs to stationary source emissions of greenhouse gases. The first two steps of regulation began on January 2, 2011 and July 1, 2011 for larger sources of greenhouse gases, while EPA's recent proposed third step would refine the PSD permitting program for greenhouse gases but would maintain the current permitting thresholds. In addition, EPA has stated its intent to propose a revised New Source Performance Standard (NSPS) for new steam generating units operated by electric utilities (and other industrial and commercial facilities) that would include limits for greenhouse gas emissions in 2012. Once EPA promulgates a NSPS for a category of new, modified or reconstructed emissions sources, it is required to establish guidelines requiring states to develop emission standards for this same category of existing sources. Thus, greenhouse gas NSPS for existing sources may be issued at some point in the future. The final rules discussed above are subject to numerous petitions for review, and challenges to future rules may be brought if and when such rules are finalized. We cannot predict at this time how further developments may affect the regulation of greenhouse gas emissions from our power plants, including capital requirements.

Litigation. Litigation related to carbon dioxide emissions continues on numerous fronts, and the outcome of such litigation could affect the power plants we own. For example, in 2004, Attorneys General from eight states and the Corporation Counsel of New York filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaint alleges that the companies' emissions of carbon dioxide contribute to global warming, which the plaintiffs claim is a public nuisance. Plaintiffs seek injunctive relief only to abate the alleged nuisance. In September 2009, the U.S. Court of Appeals for the Second Circuit vacated an earlier dismissal of the plaintiffs' claims, remanding the case back to the Southern District. In June 2011, the Supreme Court ruled that EPA's greenhouse gas rulemakings displaced federal common law nuisance claims by states and private parties. It remanded the case, however, back to the Second Circuit to decide whether state common law tort claims can continue.

Climate Change Summary. While the outcome of these matters cannot be determined at this time, adverse results in one or more of the above-described matters could result in substantial capital expenditures and/or increased operating costs at our fossil-fuel fired power plants, especially Plants Wansley and Scherer, and potentially impact the ability to permit new sources.

Coal Combustion Residuals

In May 2010, EPA proposed two alternative approaches for regulating coal combustion residuals from electric utilities: regulation as listed ''special wastes'' under hazardous wastes rules or as solid waste. Although EPA proposes to exempt the beneficial use of coal combustion residuals, a designation as hazardous waste may limit or eliminate beneficial reuse options. Adoption of either approach may require closure of or significant changes to existing storage units, extended plant outages, construction of lined landfills and groundwater monitoring facilities, and additional material management and financial assurance requirements. A variation of the second approach might not require early closure of existing wet storage facilities. In 2011, EPA issued two notices of data availability, seeking comment on the validity and propriety of the use of certain information listed in the notices or rulemaking docket to make regulatory decisions about coal combustion residuals. EPA has stated its intention to finalize this rule in late 2012. Depending upon which method of regulation EPA selects, if any, preliminary estimates by many utilities and industry groups suggest that compliance costs are greater than originally anticipated by EPA and could be significant; however, any compliance costs will depend on the final form of the rules adopted. Preliminary estimates suggest that our compliance costs could be approximately one half a billion dollars or potentially more. Estimated costs are based on pre-screening figures that should be distinguished from the more formalized cost estimates provided for projects that are more definite as to scope and timing and the ultimate impacts associated with either proposal cannot be determined with certainty at this time.

Water Use and Wastewater Issues

Since 2005, EPA has been carrying out a review of wastewater discharges from coal-fired power plants to determine whether new Steam Electric Power Generating effluent guidelines that cover wastewater discharge standards under the Clean Water Act are needed. In August 2008, EPA published an interim report on the status of the studies undertaken and the findings to date. In November 2010, EPA entered into a consent decree that requires it to propose regulations by July 2012 and to finalize such proposal by January 2014. While the updated regulations are expected to address wastewater pollutants arising from the operation of ash ponds and flue gas desulfurization units at coal-fired power plants, the impacts of such guidelines cannot be determined at this time and will depend on the development of future implementing regulations.

In February 2008, the Georgia legislature adopted a comprehensive State Water Plan that lays out statewide policies, management practices and guidance for regional water planning in Georgia. In November 2011, the Georgia Environmental Protection Division adopted regional water plans that were developed pursuant to the State Water Plan. Regional plans include resource assessments, estimates of current and future water needs and management practices. Pursuant to the State Water Plan, Georgia will consider the information contained in regional water plans when making water use permitting decisions under existing state law. Regional water plans will be reviewed periodically and may be revised in the future. In addition, the state water planning process may lead to new or revised regulations for water users in the future. Because power generation is a key use of water in Georgia, the regional water plans and any future regulations or other enforceable requirements developed in connection with the State Water Plan may have substantial effects on the operations of our facilities or future facilities that we construct or acquire. The impacts of future regulations or revisions to regional water plans on our facilities or future facilities cannot be determined at this time.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. In April 2011, EPA proposed new national requirements under section 316(b) to reduce the impact on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. Applying to existing power generating facilities withdrawing more than two million gallons per day from waters of the United

States and using at least 25% of the water exclusively for cooling, the proposal primarily requires utilities to add cooling towers on power plants that currently utilize "once through" cooling systems. While the proposed regulations would affect Plants Hatch, Vogtle, Scherer and Wansley, each of these plants already has operational cooling towers and any effects of the rule are not expected to be significant. EPA is under court order to issue a final rule in July 2012, and the ultimate effects of the rule on our affected plants will depend on the final rule and the results of any ensuing legal challenges.

Other Environmental Regulation

We are subject to other environmental statutes including, but not limited to, the Georgia Water Quality Control Act, the Georgia Hazardous Site Response Act, the Toxic Substances Control Act, the Endangered Species Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Emergency Planning and Community Right to Know Act, and to the regulations implementing these statutes. We do not believe that compliance with these statutes and regulations will have a material impact on our financial condition or results of operations. Changes to any of these laws, however, could affect many areas of our operations. Although compliance with new environmental legislation could have a significant impact on those operations, such impacts cannot be fully determined at this time and would depend in part on the final legislation and the development of implementing regulations.

As an owner, co-owner and/or operator of generating facilities, we are also subject, from time to time, to claims relating to operations and/or emissions, including actions by citizens to enforce environmental regulations and claims for personal injury due to such operations and/or emissions. We cannot predict the outcome of current or future actions, our responsibility for a share of any damages awarded, or any impact on facility operations. We do not believe, however, that current actions will have a material adverse effect on our financial position, results of operations or cash flows.

Nuclear Regulation

We are subject to the provisions of the Atomic Energy Act of 1954 (the Atomic Energy Act), which vests jurisdiction in the Nuclear Regulatory Commission over the construction and operation of nuclear reactors, particularly with regard to certain public health, safety and antitrust matters. The National Environmental Policy Act has been construed to expand the jurisdiction of the Nuclear Regulatory Commission to consider the environmental impact of a facility licensed under the Atomic Energy Act. Plants Hatch and Vogtle are being operated under licenses issued by the Nuclear Regulatory Commission. All aspects of the construction, operation and maintenance of nuclear power plants are regulated by the Commission. From time to time, new Commission regulations require changes in the design, operation and maintenance of existing nuclear reactors. Operating licenses issued by the Commission are subject to revocation, suspension or modification, and the operation of a nuclear unit may be suspended if the Commission determines that the public interest, health or safety so requires. The operating licenses issued for each unit of Plants Hatch and Vogtle expire in 2034 and 2038 and 2047 and 2049, respectively.

The Nuclear Regulatory Commission issued combined construction permits and operating licenses that allow the completion of construction and operation of two additional units at Plant Vogtle. See "OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*."

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 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 Nuclear Regulatory Commission task force issued a report with initial recommendations for enhancing nuclear reactor safety in the U.S. In March 2012, the Nuclear Regulatory Commission issued three orders and a request for information based on the task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, one class of which is in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. The staff of the Nuclear

Regulatory Commission expects to have additional implementation guidance issued by August 2012. The resulting impact of these orders and recommendations on any potential additional operating costs or capital requirements cannot be determined at this time. See "RISK FACTORS" 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.

Pursuant to the Nuclear Waste Policy Act of 1982, the federal government has the responsibility for the final disposal of commercially produced high-level radioactive waste materials, including spent nuclear fuel. This act requires the owner of nuclear facilities to enter into disposal contracts with the Department of Energy for such material. These contracts require each such owner to pay a fee, which is currently just under one dollar per megawatt-hour for the net electricity generated and sold by each of its reactors.

Contracts with the Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at Plants Hatch and Vogtle. The Department of Energy failed to begin disposing of spent fuel in 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants, is pursuing legal remedies against the Department of Energy for breach of contract. See Note 1 of Notes to Consolidated Financial Statements for information regarding the status of this litigation.

Plants Hatch and Vogtle currently have on-site spent-fuel wet storage capacity and Plant Hatch has an on-site dry storage facility. The on-site dry storage facility for Plant Hatch became operational in 2000 and can be expanded to accommodate spent fuel through the life of the plant. Plant Vogtle's spent fuel pool storage is expected to be sufficient until 2014. We expect that procurement of on-site dry storage capacity at Plant Vogtle will commence in sufficient time to maintain full-core discharge capability to the spent fuel pool. See Note 1 of Notes to Consolidated Financial Statements.

For information concerning nuclear insurance, see Note 8 of Notes to Consolidated Financial Statements. For information regarding the Nuclear Regulatory Commission's regulation relating to decommissioning of nuclear facilities and regarding the Department of Energy's assessments pursuant to the Energy Policy Act for decontamination and decommissioning of nuclear fuel enrichment facilities, see Note 1 of Notes to Consolidated Financial Statements.

Federal Power Act

General

Pursuant to the Federal Power Act, the Federal Energy Regulatory Commission is the federal agency that regulates the nation's bulk power system. We are subject to certain rules and regulations under the Federal Power Act; however, as a borrower from the Rural Utilities Service, we are exempted from certain Federal Energy Regulatory Commission regulations, including rate regulation.

Rocky Mountain

We are subject to the provisions of the Federal Power Act applicable to licensees with respect to their hydroelectric developments. Rocky Mountain is a hydroelectric project is subject to licensing by the Federal Energy Regulatory Commission. The currently effective Federal Energy Regulatory Commission license to operate the Rocky Mountain project expires in 2027. See "PROPERTIES – Generating Facilities" for additional information.

Upon or after the expiration of the license, the United States Government, by act of Congress, may take over the project, or the Federal Energy Regulatory Commission may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property taken, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property taken. If the Federal Energy Regulatory Commission does not act on the new license application prior to the expiration of the existing license, the commission is required to issue annual licenses, under the same terms and conditions of the existing license, until a new license is issued.

Energy Policy Act of 2005

The Energy Policy Act of 2005 amended the Federal Power Act to authorize the Federal Energy Regulatory Commission to establish a national electric reliability organization to develop and enforce mandatory reliability standards and to establish clear responsibility for the commission to prohibit manipulative energy trading practices. In 2006, the Federal Energy Regulatory Commission certified the North American Electric Reliability Corporation, or NERC, as the national electric reliability organization. The mandatory reliability standards developed by NERC and approved by the Federal Energy Regulatory Commission impose certain operating, record-keeping and reporting requirements on us. NERC has delegated day-to-day enforcement of its responsibilities to regional entities and SERC Reliability Corporation is the regional entity to enforce reliability in sixteen central and southeastern states, including Georgia.

As a generator owner, generator operator and participant in wholesale power transactions, we are subject to certain of these mandatory reliability standards. We have established a comprehensive formal compliance program to establish, monitor, maintain and enhance our commitment to electric reliability compliance. Although we intend to comply with all currently effective and enforceable reliability standards, we cannot provide assurance that we will always be in compliance. We are obligated to make annual self-certifications of compliance with specific requirements. SERC Reliability Corporation also conducts regular audits of us for compliance with reliability standards. We expect that existing reliability standards will continue to be refined and that new reliability standards will be developed or adopted. We could be subject to fines or penalties for violations of these standards.

ITEM 1A. RISK FACTORS

The following describes the most significant risks, in management's view, that may affect our business and financial condition or the value of our debt securities. This discussion is not exhaustive, and there may be other risks that we face which are not described below. The risks described below, as well as additional risks and uncertainties presently unknown to us or currently not deemed significant, could negatively affect our business operations, financial condition and future results of operations.

We are exposed to cost uncertainty in connection with the construction of two additional nuclear units at Plant Vogtle.

We have committed significant capital expenditures and investments to construct two additional nuclear units at Plant Vogtle. The construction of large generating plants involves significant financial risk. Factors that could lead to cost overruns, delays or the inability to complete this project include:

- performance by engineering, construction or procurement contractors, including compliance with the design specifications approved and quality standards set forth by the Nuclear Regulatory Commission;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- potential contract disputes;
- shortages and/or inconsistent quality of equipment, materials and labor;
- unforeseen engineering problems;
- permits, approvals and other regulatory matters;
- erosion of public and policymaker support;
- work stoppages;
- adverse weather conditions;
- environmental and geological conditions;
- unanticipated increases in the costs of materials and labor;
- changes in project design or scope;
- increases in our cost of debt financing; and
- delays or increased costs to interconnect our facilities to transmission grids.

No nuclear plants have been constructed in the United States using advanced designs, such as the Westinghouse AP1000 and therefore, estimating the cost of construction of any new nuclear plant is inherently uncertain. Although our engineering, procurement and construction contract for the additional units at Plant Vogtle limits our exposure to increases in construction costs, we may still be subject to certain additional expenses related to the construction of these units. We also rely on our agents for the development and construction of the additional units at Plant Vogtle and do not exercise direct control over the development and construction process.

These risks could have the effect of increasing the cost of electric service we provide to our members and, as a result, could affect their ability to perform their contractual obligations to us.

Capital expenditures are projected to be significant and will increase our long-term debt.

Over the last several years, we have acquired over 2,000 megawatts of gas-fired generation and have participated in the construction of Vogtle Units No. 3 and No. 4 in order to meet the future energy needs of our members. We have incurred approximately $1.7 billion in long-term debt through 2011 to finance these initiatives and anticipate incurring another $3.6 billion in long-term debt in order to complete these projects. We are also incurring a significant amount of new debt in connection with environmental control equipment being installed at our existing coal-fired facilities in order to comply with current environmental laws and regulations.

As of December 31, 2011, we had approximately $5.7 billion of long-term debt outstanding. By the end of 2017, when the Vogtle expansion is expected to be complete with the commercial operation of Unit No. 4, and all currently anticipated environmental retrofits are expected to be complete on our coal-fired facilities, assets, we expect that we will have approximately $8.5 billion in long-term debt outstanding. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources" and "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Capital Requirements – Capital Expenditures.*"

This significant increase in long-term debt is weakening certain of our financial metrics which could impact our credit ratings. In order to increase financial coverage during this period, since 2009 our board of directors has approved budgets to achieve a greater margins for interest ratio than the minimum 1.10 margins for interest ratio required under our first mortgage indenture. In 2009, we achieved a margins for interest ratio of 1.12, and in 2010 and 2011 we achieved margins for interest ratios of 1.14. For 2012, our board of directors approved a margins for interest ratio of 1.14. However, even with increased margins, the amount of incremental debt associated with these capital investments will continue to decrease our equity ratio during this period of increased borrowing. Any downgrade in our credit ratings could increase our borrowing costs and decrease our access to the credit and capital markets.

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years. Future environmental laws and regulations, including laws and regulations designed to address climate change, air and water quality, coal combustion byproducts and other matters may increase our compliance costs or liabilities in the future.

As with most electric utilities, we are subject to extensive federal, state and local laws and regulations regarding air and water quality which, among other things, regulate emissions of pollutants, such as particulate matter, sulfur dioxide, nitrogen oxides and mercury into the air and discharges of other pollutants, including heat, into waters. We are also subject to federal, state and local waste disposal requirements that regulate the manner of transportation, storage and disposal of various types of waste, including coal combustion byproducts.

Generally, existing environmental regulations are becoming increasingly stringent, and we may also be subject to new legislation or regulation, including legislation or regulation relating to greenhouse gas emissions or renewable energy standards. More stringent standards may require us to change the design or operation of existing facilities, change or delay the location, design, construction or operation of new facilities or purchase emission allowances. These changes or allowances may result in substantial increases in the cost of electric service to our members.

For example, in 2010, EPA proposed two alternative approaches for regulating coal combustion byproducts from electric utilities as either ''special'' wastes under hazardous waste rules or as solid wastes. Although EPA proposes to exempt the beneficial use of coal combustion byproducts, a designation as hazardous waste may limit or eliminate beneficial reuse options. Further, adoption of either approach may require closure of or significant changes to existing storage units, extended plant outages, construction of lined landfills, groundwater monitoring facilities and additional material management and financial assurance requirements. Depending upon which method of regulation EPA selects, if any, and the final form of the rules adopted, preliminary estimates suggest that our compliance costs could be approximately one half a billion dollars or potentially more.

Additionally, efforts in the United States and internationally to limit emissions of greenhouse gases, in particular, carbon dioxide, from power plants continue. Although climate change legislation has not been adopted at the federal level, EPA continues to move forward with the regulation of greenhouse gas emissions under the Clean Air Act. EPA has determined that certain greenhouse gas emissions, including carbon dioxide, from new motor vehicles endanger public health or welfare, and it has implemented a program requiring the annual reporting of greenhouse gas emissions by many industries, including the electric utility industry. Effective January 2011, EPA determined that carbon dioxide and other greenhouse gases are regulated pollutants under the Prevention of Significant Deterioration preconstruction permit program and the Title V operating permit program under the Clean Air Act, which apply to power plants and other commercial and industrial facilities. As a result, the construction of new facilities or major modifications to existing facilities could trigger the need for certain permits and the application of the best available control technology for greenhouse gas emissions. In addition, EPA plans to propose a revised New Source Performance Standard for new steam generating units operated by electric utilities in 2012 which may be finalized by the end of 2012. EPA also plans to propose New Source Performance Standard guidelines that would apply to existing coal-fired electric generating facilities, including Plants Scherer and Wansley; however, the timing of those proposed guidelines is uncertain.

To date, we have committed significant capital expenditures to achieve and maintain compliance with applicable regulatory requirements at our facilities, and we expect that we will make significant capital expenditures related to environmental compliance in the future.

While we will continue to exercise our best efforts to comply with all applicable regulations, there can be no assurance that we will always be in compliance with all current and future environmental regulations. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in the imposition of civil and criminal penalties against us, as well as the complete shutdown of individual generating units not in compliance with these regulations.

Litigation relating to environmental issues, including claims of property damage or personal injury caused by greenhouse gas emissions or alleged exposure to hazardous materials, has increased in recent years. Likewise, actions by private citizen groups to enforce environmental laws and regulations are increasingly prevalent. While management does not currently anticipate that such litigation would have a material adverse effect on our financial condition, results of operations or cash flows, the ultimate outcome of any of these actions cannot be predicted.

In addition, existing environmental laws and regulations may be revised or new laws and regulations seeking to protect public health and/or the environment may be adopted or become applicable to our facilities. Revised or additional laws and regulations, and in particular climate change regulations, could result in significant additional expense and operating restrictions on our facilities or increased compliance costs which may result in significant increases in the cost of electric service. The cost impact of legislation, regulation, new judicial interpretations of existing laws or regulations, or international obligations depends upon the specific requirements created and cannot be determined at this time.

Our access to, and cost of, capital could be adversely affected by various factors, including market conditions, limitations on the availability of federally-guaranteed loans and our credit ratings. Significant constraints on our access to, or increases in our cost of, capital may limit our ability to execute our business plan by impacting our ability to fund capital investments and could adversely affect our financial condition and results of operations.

We rely on access to external funding sources as a significant source of liquidity for capital expenditure requirements not satisfied by cash flow generated from operations. Unlike most investor-owned utilities, electric cooperatives cannot issue equity securities and therefore rely almost entirely on debt financing. Historically, we and other electric generating cooperatives have relied on federal loan programs guaranteed by the Rural Utilities Service, a branch of the U.S. Department of Agriculture, in order to meet a significant portion of our long-term financing needs, typically at a cost that was lower than traditional capital markets financing. However, the availability and magnitude of Rural Utilities Service funding levels are subject to the annual federal budget appropriations process, and therefore are subject to uncertainty because of periodic budgetary and political pressures faced by Congress. Although Congress has historically rejected proposals to curtail the Rural Utilities Service loan program, there can be no assurance that it will continue to do so. In addition, electric cooperatives nationwide continue to compete for available Rural Utilities Service funding. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service loans that may be available to us in the future. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Relationship with Rural Utilities Service" and "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Sources of Capital and Liquidity – Sources of Capital*."

In connection with our share of the cost of constructing two additional nuclear units at Plant Vogtle, in May 2010 we signed a conditional term sheet that sets forth the general terms of a loan from the Federal Financing Bank and a related loan guarantee from the Department of Energy that would fund approximately 70% of eligible project costs, not to exceed $3.057 billion. However, final approval and issuance of a loan guarantee by the Department of Energy is subject to negotiation of definitive agreements, completion of due diligence by the Department of Energy and satisfaction of other conditions. There can be no assurance that the Department of Energy will issue the loan guarantee to us.

If the amount of Rural Utilities Service-guaranteed loan funds available to us in the future is decreased or eliminated, or we are unable to ultimately secure Department of Energy-guaranteed loan funds, we would have to seek alternative sources of debt financing, which will likely be at a higher cost.

Therefore our reliance on access to both short-term and long-term capital market funding has become an increasingly important factor in our financing plans, particularly in light of the significant amount of capital investment we have planned over the next five years. We have entered into multiple credit agreements to provide significant short- and medium-term liquidity and successfully accessed the capital markets in the past to satisfy our long-term borrowing needs. We believe that we will be able to maintain sufficient access to the short- and long-term capital markets based on our current credit ratings. However, our credit ratings reflect the views of the rating agencies, which could change at any point in the future. If one or more rating agencies downgrade us, and potential investors take a similar view, our borrowing costs could increase and our potential pool of investors, funding sources and liquidity could decrease. In addition, if our credit ratings are lowered below investment grade, significant collateral calls may be triggered under certain agreements and contracts which would decrease our existing liquidity.

Our borrowing costs are also affected by prevailing interest rates. Although we have hedged a significant portion of our exposure to rising interest rates related to the construction of Vogtle Units No. 3 and No. 4, the hedges we have in place only cover a portion of our total exposure to increased interest rates. If interest rates have increased at the time we issue fixed rate debt or reset the interest rates on our variable rate debt, our interest costs will increase to the extent these increases are not offset by any interest rate hedges and our financial condition and future results of operations could be adversely affected.

In addition, certain market disruptions could constrain, at least temporarily, lenders' ability to perform their obligations under existing credit agreements and our ability to access additional sources of capital on favorable terms or at all. These disruptions include:

- market conditions generally, such as the recent uncertainty in the credit and capital markets;
- economic downturns or recessions;
- instability in domestic or foreign financial markets;
- a tightening of lending and lending standards by banks and other credit providers;
- the overall health of the energy and financial industries;
- negative events in the energy industry, such as a bankruptcy of an unrelated energy company or the occurrence of a significant natural disaster;
- lender concerns regarding potential cost overruns associated with nuclear construction;
- war or threat of war; and
- terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

If our ability to access capital becomes significantly constrained or more expensive for any of the reasons stated above or for any other reason, our ability to finance ongoing capital expenditures could be limited and our financial condition and future results of operations could be adversely affected.

We own nuclear facilities which give rise to environmental, regulatory, financial and other risks, and we are participating in the development of new nuclear facilities.

We own a 30% undivided interest in Plant Hatch and Plant Vogtle, each of which is a two-unit nuclear generating facility, and which collectively account for approximately 17% of our generating capacity and 43% of our energy generated during 2011. Our ownership interests in these facilities expose us to various risks, including:

- potential liabilities relating to harmful effects on the environment and human health resulting from the operation of these facilities and the on-site storage, handling and disposal of spent nuclear fuel;
- significant capital expenditures relating to maintenance, operation, security and repair of these facilities, including repairs or modifications required by the Nuclear Regulatory Commission;
- potential liabilities arising out of nuclear incidents caused by natural disasters, terrorist attacks or otherwise, including the payment of retrospective insurance premiums, whether at our own plants or the plants of other nuclear owners; and
- risks related to the expected cost, and funding of the expected cost, of decommissioning these facilities at the end of their operational life.

The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. If our nuclear facilities were found to be out of compliance with applicable requirements, the Nuclear Regulatory Commission may impose fines or shut down one or more units of these facilities until compliance is achieved. Revised safety requirements issued by the Nuclear Regulatory Commission have, in the past, necessitated substantial capital expenditures at other nuclear generating facilities.

A major incident at a nuclear facility anywhere in the world could cause the Nuclear Regulatory Commission to limit or prohibit the operation or licensing of any domestic nuclear unit. In response to the incident at the Fukushima Daiichi nuclear generating plant in Japan, the Nuclear Regulatory Commission is reviewing current licensing and safety-related requirements for existing and future nuclear facilities which could affect future costs of operating nuclear facilities and capital requirements. In addition, while we have no reason to anticipate a serious incident at either of our nuclear plants, if an incident did occur, it could result in substantial cost to us.

Currently, there is no national repository for spent nuclear fuel, and progress towards such a repository has been disappointing. Spent nuclear fuel from Plants Hatch and Vogtle is currently stored in on-site storage facilities. We currently forecast that the on-site storage capabilities at Plants Hatch and Vogtle can be expanded to accommodate spent fuel through the life of the plants.

We maintain an internal fund and an external trust fund for the estimated cost of decommissioning our existing nuclear facilities. However, if the values of the investments in the funds significantly decrease or the anticipated decommissioning costs significantly increase, it is possible that decommissioning costs and liabilities could exceed the amount of these funds, and we would have to collect additional revenue from our members to pay the excess costs.

In addition to our existing ownership of nuclear units, we are participating with the other co-owners of Plant Vogtle in the construction of two additional nuclear units at the Plant Vogtle site. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4.*"

We could be adversely affected if we or our operating agents are unable to continue to operate our facilities in a successful manner.

The operation of our generating facilities may be adversely impacted by various factors, including:

- the risk of equipment and information technology failure or operator error;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- compliance with electric reliability organizations' mandatory reliability and record keeping standards, including mandatory cyber security standards;
- cyber intrusion;
- the ability to maintain a qualified workforce;
- interruptions in fuel, water or material supplies;
- labor disputes;
- terrorist attacks; or
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events such as influenzas or similar occurrences.

A severe drought could reduce the availability of water and restrict or prevent the operation of certain generating facilities. These or similar negative events could interrupt or limit electric generation or increase the cost of operating our facilities, which could have the effect of increasing the cost of electric service we provide to our members and affect their ability to perform their contractual obligations to us.

A significant percentage of our energy is generated at facilities that are operated by third parties. We rely on these operating agents for the continued operation of these facilities to avoid potential interruptions in service from these facilities. If our operating agents are unable to operate these facilities, the cost of electric service we provide to our members, or the cost of replacement electric service, may increase. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Georgia Power Company" and "PROPERTIES – Co-Owners of Plants" for discussions of our relationship with Georgia Power and our co-owned facilities.

Changes in fuel prices could have an adverse effect on our cost of electric service.

We are exposed to the risk of changing prices for fuels, including coal, natural gas and uranium. We have taken steps to manage this exposure by entering into fixed or capped price contracts for some of our coal requirements. We have also entered into natural gas swap arrangements on behalf of some of our members designed to manage the exposure of those members to fluctuations in the price of natural gas. The operator of our nuclear plants manages price and supply risk through use of long-term fixed or capped price contracts with multiple vendors of uranium ore mining, conversion and enrichment services. However, these arrangements do not cover all of our and our members' risk exposure to increases in the prices of fuels. Therefore, increases in fuel prices could significantly increase the cost of electric service we provide to our members and affect their ability to perform their contractual obligations to us.

We may not be able to obtain an adequate supply of fuel, which could limit our ability to operate our facilities.

We obtain our fuel supplies, including coal, natural gas and uranium, from a number of different suppliers. Any disruptions in our fuel supplies, including disruptions due to weather, labor relations, environmental regulations, or other factors affecting our fuel suppliers, could result in us having insufficient levels of fuel supplies. For example, rail transportation bottlenecks could cause transportation companies to be unable to perform their contractual obligations to deliver coal on a timely basis which could result in lower than normal coal inventories at our coal-fired generating plants. Natural gas supplies can also be subject to disruption due to natural disasters and similar events. Any failure to maintain an adequate inventory of fuel supplies could require us to operate other generating plants at a higher cost or require our members to purchase higher-cost energy from other sources and affect their ability to perform their contractual obligations to us.

The operational life of some of our generating facilities exposes us to potential costs to continue to meet efficiency, reliability and environmental compliance standards.

Many of our generating facilities were constructed over 20 to 30 years ago and, even if maintained in accordance with good engineering practices, may require significant capital expenditures in order to maintain efficient and reliable operation. Potential operational issues associated with the age of the plants may lead to unscheduled outages, a generating facility being out of service for a period of time, or other service-related interruptions. Further, the adoption of new environmental regulations could lead to significant capital expenditures for our older generating facilities to comply with the new environmental requirements.

These expenditures and service interruptions could have the effect of increasing the cost of electric service we provide to our members and, as a result, could affect our members' ability to perform their contractual obligations to us.

We are subject to the risk that counterparties may fail to perform their contractual obligations which could adversely affect us.

We routinely execute transactions with counterparties in the energy and financial services industries. These transactions include credit facilities, interest rate options, hedges related to the market price of coal and natural gas, power sales and purchases and facility construction. Many of these transactions expose us to the risk that our counterparty may fail to perform its contractual obligations.

For example, we have purchased interest rate options from several counterparties to hedge our exposure to rising interest rates on approximately $2.2 billion of expected borrowings related to the construction of Vogtle Units No. 3 and No. 4. Although our counterparties in these transactions have posted various amounts of collateral, if any of these counterparties fails or refuses to honor its obligations, those interest rate hedges may not provide the protection we anticipated. Failure of our counterparties to perform their contractual obligations under the interest rate options or any of our other agreements could significantly increase the cost of electric service we provide to our members.

Also, as a result of continued instability in global financial markets, some of our financial institution counterparties, including participants in our committed credit facilities, have experienced various degrees of financial distress, including liquidity constraints and credit downgrades. The financial distress of these counterparties may have an adverse effect on us in the event that these counterparties default or otherwise fail to meet their contractual obligations to us.

Our ability to meet our financial obligations could be adversely affected if our members fail to perform their contractual obligations to us.

We depend primarily on revenue from our members under the wholesale power contracts to meet our financial obligations. Our members are our owners, and we do not control their operations or financial performance. Further, our members must forecast their load growth and power supply needs. If our members acquire more power supply resources than needed, whether from us or other suppliers, or fail to acquire sufficient supplies, our members' rates could increase excessively and affect financial performance. Also, in times of weak economic conditions, sales by our members may not be sufficient to cover costs without rate increases, and our members may not collect all amounts billed to their consumers. Although each member has financial covenants to set rates to maintain certain margin levels, and our members' rates are not regulated by the Georgia Public Service Commission, pressure from their consumer members not to raise rates excessively could affect financial performance. Thus, we are exposed to the risk that one or more members could default in the performance of their obligations to us under the wholesale power contracts. Our ability to satisfy our financial obligations could be adversely affected if one or more of our members, particularly one of the larger members, defaulted on their payment obligations to us. Although the wholesale power contracts obligate non-defaulting members to pay the amount of any payment default pursuant to a pro rata step-up formula, there can be no guarantee that the non-defaulting members would be able to fulfill this obligation.

Changes in power generation technology could result in the cost of our electric service being less competitive.

Our business model is to provide our members with wholesale electric power at the lowest possible cost. Other technologies currently exist or are in development, such as fuel cells, micro turbines, windmills and solar cells, that may in the future be capable of producing electric power at costs that are comparable with, or lower than, our cost of generating power. If these technologies were to develop sufficient economies of scale, the value of our generating facilities could be adversely affected.

Regardless of our financial condition, investors' ability to trade our debt securities may be limited by the absence of an active trading market and there is no assurance that any trading market will develop or continue to remain active.

Our debt securities are not listed on any national securities exchange or quoted on any automated quotation system. Although certain series of our debt securities at times have an active trading market, certain of our debt securities have no active trading market, including some of our outstanding auction rate securities that have been subject to continued failed auctions since 2008. Various dealers have made a market in certain of our debt securities. We have remarketing agreements in place for certain of our variable rate bonds and if a particular series of new debt securities is offered through underwriters, those underwriters may attempt to make a market in the debt securities. Dealers or underwriters have no obligation to make a market in any of our debt securities and may terminate any market-making activities at any time, for any reason, without notice. As a result, we cannot provide any assurance as to the liquidity of any trading market for our debt securities, the ability of holders to sell their debt securities or the price at which holders will be able to sell their debt securities.

Even in an active trading market, future prices of our debt securities will depend on several factors, including prevailing interest rates, the then-current ratings assigned to the debt securities, the amount of our debt securities outstanding, the market for similar securities and our operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Generating Facilities

The following table sets forth certain information with respect to our generating facilities, all of which are in commercial operation.

Facilities	Type of Fuel	Percentage Interest	Our Share of Nameplate Capacity (MW)	Commercial Operation Date	License Expiration Date
Plant Hatch (near Baxley, Ga.)					
Unit No. 1	Nuclear	30	269.9	1975	2034
Unit No. 2	Nuclear	30	268.8	1979	2038
Plant Vogtle (near Waynesboro, Ga.)					
Unit No. 1	Nuclear	30	348.0	1987	2047
Unit No. 2	Nuclear	30	348.0	1989	2049
Plant Wansley (near Carrollton, Ga.)					
Unit No. 1	Coal	30	259.5	1976	N/A(1)
Unit No. 2	Coal	30	259.5	1978	N/A(1)
Combustion Turbine	Oil	30	14.8	1980	N/A(1)
Plant Scherer (near Forsyth, Ga.)					
Unit No. 1	Coal	60	490.8	1982	N/A(1)
Unit No. 2	Coal	60	490.8	1984	N/A(1)
Rocky Mountain (near Rome, Ga.)	Pumped Storage Hydro	74.61	632.5	1995	2027
Doyle (near Monroe, Ga.)	Gas	100	325.0(2)	2000	N/A(1)
Talbot (near Columbus, Ga.)					
Units No. 1-4	Gas	100	412.0	2002	N/A(1)
Units No. 5-6	Gas-Oil	100	206.0	2003	N/A(1)
Chattahoochee (near Carrollton, Ga.)	Gas	100	468.0	2003	N/A(1)
Hawk Road (near Franklin, Ga.)	Gas	100	500.0	2001	N/A(1)
Hartwell (near Hartwell, Ga.)	Gas-Oil	100	300.0	1994	N/A(1)
Murray (near Dalton, Ga.)					
Unit No. 1	Gas	100	630.0	2002	N/A(1)
Unit No. 2	Gas	100	620.0	2002	N/A(1)

(1) Fossil-fired units do not operate under operating licenses similar to those granted to nuclear units by the Nuclear Regulatory Commission and to hydroelectric plants by Federal Energy Regulatory Commission.

(2) Nominal plant capacity identified in the power purchase and sale agreement with Doyle I, LLC. (See "– The Plant Agreements – *Doyle.*")

Plant Performance

The following table sets forth certain operating performance information of each of our generating facilities:

Unit	Summer Planning Reserve Capacity(1) (Megawatts)	Equivalent Availability(2) 2011	2010	2009	Capacity Factor(3) 2011	2010	2009
Plant Hatch							
Unit No. 1	262.2	97%	84%	93%	98%	85%	93%
Unit No. 2	264.3	78	95	67	78	96	67
Plant Vogtle							
Unit No. 1	344.5	89	100	89	91	102	91
Unit No. 2	344.7	93	91	99	94	93	100
Plant Wansley							
Unit No. 1	261.6	96	87	87	56	53	51
Unit No. 2	261.6	86	97	95	47	67	45
Combustion Turbine(4)	0	61	37	61	0	0	0
Plant Scherer							
Unit No. 1	501.2	75	99	79	64	89	70
Unit No. 2	509.0	76	98	81	66	90	72
Rocky Mountain(5)							
Unit No. 1	272.3	97	62	74	20	16	18
Unit No. 2	272.3	61	75	96	12	13	19
Unit No. 3	272.3	84	89	75	12	17	15
Doyle(5)(6)	348.0	96	98	100	5	1	1
Talbot(5)	656.3	82	93	94	5	4	1
Chattahoochee	470.0	62	65	91	46	38	53
Hawk Road(5)(7)	486.1	51	87	94	0	5	0
Hartwell(5)(7)	298.0	94	93	99	8	7	3
Murray(7)							
Unit No. 1	630.0	89	n/a	n/a	34	n/a	n/a
Unit No. 2	620.0	79	n/a	n/a	21	n/a	n/a
TOTAL	7,074.4						

(1) Summer Planning Reserve Capacity is the amount used for 2012 capacity reserve planning.

(2) Equivalent Availability is a measure of the percentage of time that a unit was available to generate if called upon, adjusted for periods when the unit is derated from its rated capacity.

(3) Capacity Factor is a measure of the actual output of a unit as a percentage of its potential output.

(4) The Wansley combustion turbine is used primarily for emergency service and is rarely operated except for testing.

(5) Rocky Mountain, Doyle, Talbot, Hawk Road and Hartwell, primarily operate as peaking plants, which results in low capacity factors.

(6) Equivalent Availability for each of Doyle's five units is measured only during the period May 15 – September 15, reflecting the contractual availability commitment of Doyle I, LLC. We may dispatch the units during other periods if the units are available.

(7) The 2011 operating performance factors for Murray, which we acquired during 2011, are based on the entire twelve months of 2011. The 2009 operating performance factors for Hawk Road and Hartwell, which we acquired during 2009, are based on the entire twelve months of 2009.

The nuclear refueling cycle for Plants Hatch and Vogtle exceeds twelve months. Therefore, in some calendar years the units at these plants are not taken out of service for refueling, resulting in higher levels of equivalent availability and capacity factor.

Fuel Supply

Coal. Coal for Plant Wansley is currently purchased under term contracts and in spot market transactions, primarily from coal mines in the eastern United States. As of February 29, 2012, we had a 91-day coal supply at Plant Wansley based on continuous operation.

Coal for Scherer Units No. 1 and No. 2 is purchased under term contracts and in spot market transactions. As of February 29, 2012, our coal stockpile at Plant Scherer contained a 59-day supply based on continuous operation. Plant Scherer burns sub-bituminous coal purchased from coal mines in the Powder River Basin in Wyoming.

We separately dispatch Plant Wansley and Plant Scherer, but use Georgia Power as our agent for fuel procurement. We currently lease approximately 1,200 rail cars to transport coal to these two facilities.

For information relating to the impact that the Clean Air Act may have on our coal-fired facilities, see "BUSINESS – ENVIRONMENTAL AND OTHER REGULATION – Air Quality."

Nuclear Fuel. Georgia Power, as operating agent, has the responsibility to procure nuclear fuel for Plants Hatch and Vogtle. Georgia Power has contracted with Southern Nuclear to operate these plants, including nuclear fuel procurement. Southern Nuclear has contracted with multiple suppliers for uranium ore, conversion services, enrichment services and fuel fabrication to satisfy nuclear fuel requirements. Most contracts are short to medium-term. The nuclear fuel supply and related services are expected to be adequate to satisfy current and future nuclear generation requirements.

Natural Gas. We purchase the natural gas, including transportation and other related services, needed to operate Doyle, Talbot, Chattahoochee, Hawk Road, Hartwell and Murray. We purchase natural gas in the spot market and under agreements at indexed prices. We have entered into hedge agreements to manage a portion of our exposure to fluctuations in the market price of natural gas. We manage exposure to such risks only with respect to members that elect to receive such services. We purchase transportation under long-term firm and short-term firm and non-firm contracts. We have also contracted with Petal Gas Storage, LLC to provide 800,000 MMBtu of firm natural gas storage services and related firm transportation. See "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK – Commodity Price Risk."

Co-Owners of Plants

Plants Hatch, Vogtle, Wansley and Scherer Units No. 1 and No. 2 are co-owned by Georgia Power, the Municipal Electric Authority of Georgia, the City of Dalton and us, and Rocky Mountain is co-owned by Georgia Power and us. Each co-owner owns or leases undivided interests in the amounts shown in the following table, which excludes the Plant Wansley combustion turbine. We are the operating agent for Rocky Mountain. Georgia Power is the operating agent for each of the other plants.

	Nuclear				Coal-Fired				Pumped Storage		
	Plant Hatch		Plant Vogtle		Plant Wansley		Scherer Units No. 1 & No. 2		Rocky Mountain		Total
	%	MW(1)	%	MW(1)	%	MW(1)	%	MW(1)	%	MW(1)	MW(1)
Oglethorpe	30.0	539	30.0	696	30.0	519	60.0	982	74.61	633	3,369
Georgia Power	50.1	900	45.7	1,060	53.5	926	8.4	137	25.39	215	3,238
MEAG	17.7	318	22.7	527	15.1	261	30.2	494	–	–	1,600
Dalton	2.2	39	1.6	37	1.4	24	1.4	23	–	–	123
Total	100.0	1,796	100.0	2,320	100.0	1,730	100.0	1,636	100.00	848	8,330

(1) Based on nameplate ratings.

Georgia Power Company

Georgia Power is a wholly owned subsidiary of The Southern Company and is engaged primarily in the generation and purchase of electric energy and the transmission, distribution and sale of this energy. Georgia Power distributes and sells energy within the State of Georgia at retail in over 600 communities, including Athens, Atlanta, Augusta, Columbus, Macon, Rome and Valdosta, as well as in rural areas, and at wholesale to some of our members, the Municipal Electric Authority of Georgia and two municipalities. Georgia Power is the largest supplier of electric energy in the State of Georgia. See ''BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Georgia Power Company.'' Georgia Power is subject to the informational requirements of the Exchange Act, and, in accordance therewith, files reports and other information with the SEC.

Municipal Electric Authority of Georgia

The Municipal Electric Authority of Georgia, also known as MEAG Power, is a state-chartered, municipal joint-action agency that provides capacity and energy to its membership of 49 municipal electric utilities, including 48 cities and one county in the State of Georgia. MEAG Power has wholesale take-or-pay power sales contracts with each of its 49 participants that extend to June 2054. The participants are located in 39 of the State's 159 counties and collectively serve approximately 309,000 electric consumers (meters). MEAG Power is the State's third largest power supplier behind Georgia Power and us.

City of Dalton, Georgia

Dalton Utilities is a combined utility that provides electric, gas, water and wastewater services to the city of Dalton, located in northwest Georgia, and some of the surrounding communities. It presently serves more than 65,000 residential, commercial and industrial electric customers.

The Plant Agreements

Plants Hatch, Wansley, Vogtle and Scherer

Our rights and obligations with respect to Plants Hatch, Wansley, Vogtle and Scherer are contained in a number of contracts between Georgia Power and us and, in some instances, MEAG Power and the City of Dalton. We are a party to four Purchase and Ownership Participation Agreements (Ownership Agreements) under which we acquired from Georgia Power a 30% undivided interest in each of Plants Hatch, Wansley and Vogtle, a 60% undivided interest in Scherer Units No. 1 and No. 2 and a 30% undivided interest in those facilities at Plant Scherer intended to be used in common by Scherer Units No. 1, No. 2, No. 3 and No. 4 (the Scherer Common Facilities). We have also entered into four Operating Agreements (Operating Agreements) relating to the operation and maintenance of Plants Hatch, Wansley, Vogtle and Scherer, respectively. The Ownership Agreements and Operating Agreements relating to Plants Hatch and Wansley are two-party agreements between Georgia Power and us. The Ownership Agreements and Operating Agreements relating to Plants Vogtle and Scherer are agreements among Georgia Power, MEAG Power, the City of

Dalton and us. The parties to each Ownership Agreement and Operating Agreement are referred to as ''participants'' with respect to each such agreement.

In 1985, in four transactions, we sold our entire 60% undivided ownership interest in Scherer Unit No. 2 to four separate owner trusts established by institutional investors. We retained all of our rights and obligations as a participant under the Ownership and Operating Agreements relating to Scherer Unit No. 2 for the term of the leases. The leases include lease renewal and fair market value purchase options at specified dates. See Note 4 of Notes to Consolidated Financial Statements. In the following discussion, references to participants ''owning'' a specified percentage of interests include our rights as a deemed owner with respect to our leased interests in Scherer Unit No. 2.

The Ownership Agreements appoint Georgia Power as agent with sole authority and responsibility for, among other things, the planning, licensing, design, construction, renewal, addition, modification and disposal of Plants Hatch, Vogtle, Wansley and Scherer Units No. 1 and No. 2 and the facilities used in common at Plant Scherer. Each Operating Agreement gives Georgia Power, as agent, sole authority and responsibility for the management, control, maintenance and operation of the plant to which it relates. Each Operating Agreement also provides for the use of power and energy from the plant and the sharing of the costs of the plant by the participants in accordance with their respective interests in the plant. In performing its responsibilities under the Ownership and Operating Agreements, Georgia Power is required to comply with prudent utility practices. Georgia Power's liabilities with respect to its duties under the Ownership and Operating Agreements are limited by the terms of these agreements.

Under the Ownership Agreements, we are obligated to pay a percentage of capital costs of the respective plants, as incurred, equal to the percentage interest which we own or lease at each plant. With respect to Scherer Units No. 1 and No. 2, the participants have certain limited rights to disapprove capital budgets proposed by Georgia Power and to substitute alternative capital budgets. With respect to Plants Hatch and Vogtle, any co-owner has the right to disapprove large discretionary capital improvements.

In 1993, the co-owners of Plants Hatch and Vogtle entered into the Amended and Restated Nuclear Managing Board Agreement, which provides for a managing board to coordinate the implementation and administration of the Plant Hatch and Plant Vogtle Ownership and Operating Agreements, provides for increased rights for the co-owners regarding certain decisions and allows Georgia Power to contract with a third party for the operation of the nuclear units. In March 1997, Georgia Power designated Southern Nuclear as the operator of Plants Hatch and Vogtle, pursuant to the Nuclear Operating Agreement between Georgia Power and Southern Nuclear, which the co-owners had previously approved. In connection with the amendments to the Plant Scherer Ownership and Operating Agreements, the co-owners of Plant Scherer entered into the Plant Scherer Managing Board Agreement which provides for a managing board to coordinate the implementation and administration of the Plant Scherer Ownership and Operating Agreements and provides for increased rights for the co-owners regarding certain decisions, but does not alter Georgia Power's role as agent with respect to Plant Scherer.

The Operating Agreements provide that we are entitled to a percentage of the net capacity and net energy output of each plant or unit equal to our percentage undivided interest owned or leased in such plant or unit. Georgia Power, as agent, schedules and dispatches Plants Hatch and Vogtle. The Plant Scherer and Wansley ownership and operating agreements allow each co-owner (i) to dispatch separately its respective ownership interest in conjunction with contracting separately for long-term coal purchases procured by Georgia Power and (ii) to procure separately long-term coal purchases. We separately dispatch our ownership share of Scherer Units No. 1 and No. 2 and of Plant Wansley.

For Plants Hatch and Vogtle, each participant is responsible for a percentage of operating costs (as defined in the Operating Agreements) and fuel costs of each plant or unit equal to the percentage of its undivided interest which is owned or leased in such plant or unit. For Scherer Units No. 1 and No. 2 and for Plant Wansley, each party is responsible for its fuel costs and for variable operating costs in proportion to the net energy output for its ownership interest, and is responsible for a percentage of fixed operating costs equal to the percentage of its undivided interest which is owned or leased in such plant or unit. Georgia Power is required to furnish budgets for operating costs, fuel plans and scheduled maintenance plans. In the case of

Scherer Units No. 1 and No. 2, the participants have limited rights to disapprove such budgets proposed by Georgia Power and to substitute alternative budgets. The Ownership Agreements and Operating Agreements provide that, should a participant fail to make any payment when due, among other things, such nonpaying participant's rights to output of capacity and energy would be suspended.

The Operating Agreements for Plant Hatch and Plant Vogtle will remain in effect with respect to each unit for so long as a Nuclear Regulatory Commission operating license exists for such unit. See "BUSINESS – ENVIRONMENTAL AND OTHER REGULATION – Nuclear Regulation." The Operating Agreement for Plant Wansley will remain in effect with respect to Plant Wansley Units No. 1 and No. 2 until 2016 and 2018, respectively. The Operating Agreement for Scherer Units No. 1 and No. 2 will remain in effect with respect to Scherer Units No. 1 and No. 2 until 2022 and 2024, respectively. Upon termination of each Operating Agreement, following any extension agreed to by the parties, Georgia Power will retain such powers as are necessary in connection with the disposition of the property of the applicable plant, and the rights and obligations of the parties shall continue with respect to actions and expenses taken or incurred in connection with such disposition.

In conjunction with the development of additional units at Plant Vogtle (see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources"), we, Georgia Power, MEAG Power and the City of Dalton entered into amendments to the Operating Agreement for Plant Vogtle and the Nuclear Managing Board Agreement, and entered into an Ownership Agreement that governs participation in Vogtle Units No. 3 and No. 4.

Rocky Mountain

The Rocky Mountain Pumped Storage Hydroelectric Ownership Participation Agreement, by and between us and Georgia Power (the Rocky Mountain Ownership Agreement), appoints us as agent with sole authority and responsibility for, among other things, the planning, licensing, design, construction, operation, maintenance and disposal of Rocky Mountain. The Rocky Mountain Pumped Storage Hydroelectric Project Operating Agreement (the Rocky Mountain Operating Agreement) gives us, as agent, sole authority and responsibility for the management, control, maintenance and operation of Rocky Mountain.

In general, each co-owner is responsible for payment of its respective ownership share of all operating costs and pumping energy costs (as defined in the Rocky Mountain Operating Agreement) as well as costs incurred as a result of any separate schedule or independent dispatch. A co-owner's share of net available capacity and net energy is the same as its respective ownership interest under the Rocky Mountain Ownership Agreement. We and Georgia Power have each elected to schedule separately our respective ownership interests. The Rocky Mountain Operating Agreement will terminate in 2035. The Rocky Mountain Ownership and Operating Agreements provide that, should a co-owner fail to make any payment when due, among other things, such non-paying co-owner's rights to output of capacity and energy or to exercise any other right of a co-owner would be suspended until all amounts due, with interest, had been paid. The capacity and energy of a non-paying co-owner may be purchased by a paying co-owner or sold to a third party.

In late 1996 and early 1997, we entered into lease transactions for our 74.61% undivided ownership interest in Rocky Mountain. Under the terms of these transactions, we leased the facility to three institutional investors for the useful life of the facility, who in turn leased it back to us for a term of 30 years. We will continue to control and operate Rocky Mountain during the leaseback term. For more information about the structure of these lease transactions, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Off-Balance Sheet Arrangements – Rocky Mountain Lease Arrangements.*"

Doyle

We have an agreement with Doyle I LLC, a limited liability company owned by one of our members, Walton EMC, to purchase the output of a gas-fired combustion turbine generating facility through May 15, 2015.

During the term of the agreement, we have the right and obligation to purchase all of the capacity and energy from the facility. We are obligated to pay to Doyle I, LLC each month a capacity charge based on a performance rating and an energy charge equal to all costs of operating the facility. We are also obligated to pay the actual operation and maintenance costs and the costs of capital improvements. We are responsible for supplying all natural gas necessary to operate the facility. We have the right to dispatch the facility.

Doyle I, LLC operates the facility. Doyle I, LLC must make the units available from May 15 to September 15 each year. Subject to air permit and other limitations, we may dispatch the facility at other times to the extent that the facility is available.

We have an option to purchase the facility at the end of the term of the agreement at a fixed price. We account for this agreement as a capital lease of the facility for financial reporting purposes (see Note 4 of Notes to Consolidated Financial Statements).

ITEM 3. LEGAL PROCEEDINGS

We are a party to various actions and proceedings incidental to our normal business. Liability in the event of final adverse determinations in any of these matters is either covered by insurance or, in the opinion of our management, after consultation with counsel, should not in the aggregate have a material adverse effect on the our financial position or results of operations.

For information about environmental matters that could have an effect on us, see Note 11 of Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Not applicable.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial data. The financial data presented as of the end of and for each year in the five-year period ended December 31, 2011, has been derived from our audited financial statements. This data should be read in conjunction with "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" and the "FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA."

(dollars in thousands)

	2011	2010	2009	2008	2007
STATEMENTS OF REVENUES AND EXPENSES DATA					
Operating revenues:					
Sales to Members	**$ 1,224,238**	$ 1,292,667	$ 1,144,012	$ 1,237,649	$ 1,149,657
Sales to non-Members	**166,040**	1,478	1,249	1,111	1,585
Total operating revenues	**1,390,278**	1,294,145	1,145,261	1,238,760	1,151,242
Operating expenses:					
Fuel	**527,191**	481,379	360,412	466,205	415,125
Production	**357,069**	332,236	285,654	278,654	246,281
Purchased power	**60,590**	78,810	123,105	160,133	155,005
Depreciation and amortization	**199,040**	131,491	125,600	119,540	131,434
Accretion	**18,249**	17,131	18,261	17,149	16,169
Deferral of Hawk Road and Murray Energy facilities effect on net margin	**(9,681)**	13,849	8,107	–	–
Total operating expenses	**1,152,458**	1,054,896	921,139	1,041,681	964,014
Operating margin	**237,820**	239,249	224,122	197,079	187,228
Other income, net	**44,264**	43,651	42,728	43,381	54,854
Net interest charges	**(244,347)**	(249,167)	(240,460)	(221,201)	(223,021)
Net margin	**$ 37,737**	$ 33,733	$ 26,390	$ 19,259	$ 19,061
BALANCE SHEET DATA					
Electric plant, net:					
In service	**$ 4,007,281**	$ 3,570,522	$ 3,557,723	$ 3,152,911	$ 3,161,954
Nuclear fuel, at amortized cost	**284,205**	249,563	215,949	179,020	130,138
Construction work in progress	**1,784,264**	1,195,475	626,824	307,464	189,102
Total electric plant	**$ 6,075,750**	$ 5,015,560	$ 4,400,496	$ 3,639,395	$ 3,481,194
Total assets	**$ 8,078,829**	$ 6,997,062	$ 6,370,234	$ 5,044,452	$ 4,937,320
Capitalization:					
Long-term debt	**$ 5,692,503**	$ 4,796,154	$ 4,267,966	$ 3,361,463	$ 3,409,038
Obligations under capital leases	**191,900**	212,561	239,461	264,107	286,729
Obligations under Rocky Mountain transactions	**132,048**	123,573	115,641	108,219	101,272
Patronage capital and membership fees	**633,689**	595,952	562,219	535,829	516,570
Accumulated other comprehensive loss	**618**	(469)	(1,253)	(1,348)	(32,691)
Subtotal	**6,650,758**	5,727,771	5,184,034	4,268,270	4,280,918
Less: long-term debt and capital leases due within one year	**(172,818)**	(170,947)	(119,241)	(110,647)	(143,400)
Less: unamortized bond discounts on long-term debt	**(1,879)**	(1,353)	(260)	–	–
Total capitalization	**$ 6,476,061**	$ 5,555,471	$ 5,064,533	$ 4,157,623	$ 4,137,518
Property additions	**$ 839,503**	$ 669,206	$ 627,148	$ 353,831	$ 194,739
OTHER DATA					
Energy supply (megawatt-hours):					
Generated	**22,296,829**	22,599,257	19,699,706	21,906,888	21,577,805
Purchased	**287,522**	417,094	779,108	1,755,225	1,593,864
Available for sale	**22,584,351**	23,016,351	20,478,814	23,662,113	23,171,669
Member revenues per kWh sold	**6.25¢**	5.71¢	5.67¢	5.31¢	5.04¢

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

Forward-Looking Statements and Associated Risks

This annual report contains forward-looking statements, including statements regarding, among other items, (i) anticipated trends in our business, (ii) our future power supply requirements, resources and arrangements, (iii) our expected future capital expenditures and (iv) disclosures regarding market risk included in ''QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.'' Some forward-looking statements can be identified by use of terms such as ''may,'' ''will,'' ''expects,'' ''anticipates,'' ''believes,'' ''intends,'' ''projects,'' ''plans'' or similar terms. These forward-looking statements are based largely on our current expectations and are subject to a number of risks and uncertainties, some of which are beyond our control. For some of the factors that could cause actual results to differ materially from those anticipated by these forward-looking statements, see ''RISK FACTORS.'' In light of these risks and uncertainties, we can give no assurance that events anticipated by the forward-looking statements contained in this annual report will in fact transpire.

Executive Overview

General

We are a not-for-profit electric cooperative whose principal business is providing wholesale electric service to our 39 members. Consequently, the vast majority of our revenues and cash flow are derived from sales to our members pursuant to long-term, take-or-pay wholesale power contracts that extend through 2050. These contracts obligate our members jointly and severally to pay all of our costs and expenses associated with owning and operating our power supply business. To that end, our existing rate structure provides for a pass-through of actual energy costs. Charges for fixed costs, including capacity, other non-energy charges, debt service obligations and the margin required to meet our budgeted margins for interest ratio are carefully managed throughout the year to ensure that sufficient capacity-related revenues are produced. This structure provides us with the ability to manage our revenues to assure full recovery of our costs in rates and has enabled us to consistently meet our financial obligations since our formation in 1974.

Expansion of Generation Capacity

Over the last several years, we have focused our efforts on developing and acquiring generation resources that offer our members, through us, greater ownership and control over their generation needs in order to mitigate their reliance on third-party contracts. To advance these efforts, we have taken the following actions:

- Through our agent, Georgia Power, we and the other co-owners of Plant Vogtle have contracted with Southern Nuclear, Westinghouse and Stone & Webster, experienced developers and contractors, to construct two additional nuclear units at the Plant Vogtle site. The additional units will have an aggregate generating capacity of approximately 2,200 megawatts and our 30% undivided interest will entitle us to approximately 660 megawatts of baseload generating capacity. On February 10, 2012, the Nuclear Regulatory Commission issued the combined construction permits and operating licenses for the new units which have planned commercial operation dates of 2016 and 2017. The estimated total cost for our interest in the two units, including allowance for funds used during construction, is approximately $4.2 billion and, as of December 31, 2011, our construction work in progress for this project was approximately $1.3 billion.
- In May 2009, we acquired the Hawk Road Energy Facility, a 500-megawatt peaking facility with three combustion turbines in Heard County, Georgia. The purchase price for the facility was $105 million. In addition, we assumed a related purchase and sale agreement with seven of our members, which was valued as a liability of $98 million at the time of closing.
- In October 2009, we acquired the Hartwell Energy Facility, a 300-megawatt oil and gas-fired peaking facility in Hart County, Georgia that consists of two combustion turbines. The purchase price for the facility was $148.5 million.
- In April 2011, we acquired the Murray Energy Facility, a 1,250-megawatt natural gas-fired facility near Dalton, Georgia that consists of two

combined cycle units. The purchase price for the facility was $530.3 million.

- With the acquisition of Murray, we cancelled a 605-megawatt combined cycle facility under development, which was projected to cost approximately $750 million.
- We and our members continue to evaluate constructing or acquiring additional generation resources.

In connection with expanding our generation capacity, our total assets have increased to approximately $8.1 billion at December 31, 2011 from $5.0 billion at December 31, 2008, and our long-term debt and capital leases have increased to $5.9 billion from $3.6 billion during the same period. As we continue to construct Vogtle Units No. 3 and No. 4, our assets and long-term debt will each continue to increase.

In addition to the construction of Vogtle Units No. 3 and No. 4, we forecast that capital expenditures required for existing generating facilities will be approximately $1.1 billion through 2017, which includes normal additions and replacements to existing plants as well as projects to maintain and achieve compliance with current environmental requirements. Importantly, this forecast does not include capital expenditures or increased operational expenses for Plants Wansley and Scherer due to climate change or coal combustion by-products regulation that might be adopted in the future.

2011 Financial Results

Despite continued economic pressures, we are well positioned, both financially and operationally, to fulfill our obligations to our members, bondholders and creditors. In this regard, our revenues in 2011 were more than sufficient to recover all of our costs and to satisfy all of our debt service obligations and financial covenants. Specifically, we recorded a net margin of $37.7 million in 2011, which achieved the 1.14 margins for interest ratio approved by our board of directors and exceeded the margins for interest ratio of 1.10 required to meet the rate covenant under our first mortgage indenture.

In light of current financial market conditions and the period of increased capital requirements noted above, we believe it was prudent to increase our margins for interest coverage. Since 2009, we have targeted and achieved higher margins than necessary to meet the margins for interest ratio covenant of 1.10 required under the first mortgage indenture. As a result of the margins achieved over that timeframe, our patronage capital has increased to $633.7 million at December 31, 2011 from $535.8 million at December 31, 2008. For 2012, we are again targeting a margins for interest ratio of 1.14, effectively increasing our annual margins by 40% over the minimum required level. Over the next few years, our board of directors will continue to evaluate our financial metrics and may choose to further increase or decrease the margins for interest ratio in the future.

Liquidity Position

Our liquidity position is one of our most positive attributes contributing to our solid financial standing. Despite recent disruptions in the global economic and financial markets, we strengthened our liquidity position by significantly upsizing and restructuring our primary credit facility from $475 million to $1.265 billion in June 2011. We also closed on a $260 million term loan in April 2011 to provide interim financing for the acquisition of Murray and increased another credit facility from $50 to $110 million in September 2011. At December 31, 2011, we had $1.7 billion of unrestricted available liquidity. Our liquidity is comprised of a diversified, cost-effective mix of cash (including short-term investments), committed lines of credit and commercial paper.

In addition to maintaining more than adequate coverage for short-term credit needs, we have also taken advantage of historically low interest rates to secure favorable long-term financing for some of our construction and acquisition activity. The Rural Utilities Service has approved loans to provide long-term funding for Hawk Road, Hartwell and Murray, and we have issued $1.15 billion of taxable first mortgage bonds to finance a portion of our costs associated with the additional units at Plant Vogtle. We have also executed a conditional commitment letter with the Department of Energy to secure a long-term loan guarantee for up to 70%, or $3.057 billion, of eligible project costs for the additional units at Plant Vogtle.

Outlook for 2012

We remain focused on providing reliable, cost-effective energy to our members and the

4.1 million people they serve. There are, nevertheless, certain risks and challenges that we must address, including:

- Continued ability to access financial markets and availability of federally-guaranteed funding to support our significant future capital requirements;
- Managing the effects of increased environmental regulation of fossil fuel-fired power plants, most likely leading, for example, to new controls for carbon dioxide emissions and more stringent controls for other emissions, or disposal of coal combustion by-products, particularly at Plants Wansley and Scherer; and
- General economic conditions in the U.S. and the related impacts on our members and their consumers.

We believe that we continue to be well positioned to provide reliable, cost-effective energy to our members and their consumers. As we manage our risks, we intend to keep doing what we have done so successfully for the last 38 years, including, among other things:

- Maintaining a balanced diversity of generating resources – primarily nuclear, coal, natural gas and hydro;
- Maintaining strong liquidity to fulfill current obligations and to finance future capital expenditures; and
- Working with our members, as necessary, to evaluate new resources to be acquired or developed by us to help meet our members' power supply requirements.

Summary of Cooperative Operations

Margins and Patronage Capital

We operate on a not-for-profit basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to establish reasonable reserves and meet certain financial coverage requirements. Revenues in excess of current period costs in any year are designated as net margin in our statements of revenues and expenses. Retained net margins are designated on our balance sheets as patronage capital, which is allocated to each of our members on the basis of its fixed percentage capacity costs responsibilities in our generation and purchased power resources. Since our formation in 1974, we have generated a positive net margin in each year and had $634 million in patronage capital and membership fees as of December 31, 2011. Our equity ratio, calculated as patronage capital and membership fees divided by total capitalization and long-term debt due within one year, was 9.5% at December 31, 2011 and 10.4% at December 31, 2010.

Patronage capital constitutes our principal equity. Any distribution of patronage capital is subject to the discretion of our board of directors. However, under the first mortgage indenture, we are prohibited from making any distribution of patronage capital to our members if, at the time of or after giving effect to the distribution, (i) an event of default exists under the first mortgage indenture, (ii) our equity as of the end of the immediately preceding fiscal quarter is less than 20% of our total long-term debt and equities, or (iii) the aggregate amount expended for distributions on or after the date on which our equity first reaches 20% of our total long-term debt and equities exceeds 35% of our aggregate net margins earned after such date. This last restriction, however, will not apply if, after giving effect to such distribution, our equity as of the end of the immediately preceding fiscal quarter is not less than 30% of our total long-term debt and equities.

Rates and Regulation

Pursuant to the wholesale power contracts between us and each of our members, we are required to design capacity and energy rates that generate revenues sufficient to recover all costs, including the payments of principal and interest on our indebtedness, to establish and maintain reasonable margins and to meet the financial coverage requirements under the first mortgage indenture.

The rate schedule under the wholesale power contracts assigns on a long-term basis, the responsibility for our fixed costs to each of our members. The monthly charges for capacity and other non-energy charges are based on a rate formula using our budget. Energy charges are based on actual energy costs, including fuel costs, variable operations and maintenance costs, and purchased energy costs.

Under the first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates that are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10.

The margins for interest ratio is determined by dividing margins for interest by interest charges. Margins for interest equals the sum of (i) our net margins (after certain defined adjustments), (ii) interest charges and (iii) any amount included in net margins for accruals for federal or state income taxes. The definition of margins for interest takes into account any item of net margin, loss, gain or expenditure of any of our affiliates or subsidiaries only if we have received such net margins or gains as a dividend or other distribution from such affiliate or subsidiary or if we have made a payment with respect to such losses or expenditures. The interest charges in the margins for interest ratio is comprised of interest on debt secured under our first mortgage indenture.

We review our financial results frequently throughout the year, and with board approval, make budget adjustments when and as necessary to ensure that we generate revenues sufficient to recover all costs and to meet our budgeted margins for interest ratio. In the event we were to fall short of the minimum 1.10 margins for interest ratio required under the first mortgage indenture at year end, the rate schedule includes a prior period adjustment mechanism designed to recover the shortfall without any additional action by our board of directors. Amounts, if any, by which we fall short of the minimum 1.10 margins for interest ratio would be accrued as of December 31 of the applicable year and collected from our members from April through December of the following year.

Prior to 2009, we budgeted and achieved an annual margins for interest ratio of 1.10, the minimum required by the first mortgage indenture. However, to enhance margin coverage during this period of generation facility construction and acquisition, our board of directors approved budgets for both 2011 and 2010 to achieve a 1.14 margins for interest ratio and a budget for 2009 to achieve a margins for interest ratio of 1.12. As a result, we achieved a margins for interest ratio of 1.14 in 2011 and 2010 and 1.12 in 2009. Our board of directors approved a budget for 2012 to achieve a 1.14 margins for interest ratio. As our construction and acquisition program evolves, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below the 1.10 margins for interest ratio required under our first mortgage indenture.

Under the first mortgage indenture and related loan contract with the Rural Utilities Service, adjustments to our rates to reflect changes in our budgets are generally not subject to Rural Utilities Service approval. Changes to the rate schedule under the wholesale power contracts are generally subject to Rural Utilities Service approval. Our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

Accounting Policies

Basis of Accounting

We follow generally accepted accounting principles in the United States and the practices prescribed in the Uniform System of Accounts of the Federal Energy Regulatory Commission as modified and adopted by the Rural Utilities Service.

Critical Accounting Policy

We have determined that the following accounting policy is critical to understanding and evaluating our financial condition and results of operations and requires our management to make estimates and assumptions about matters that were uncertain at the time of the preparation of our financial statements. Changes in these estimates and assumptions by our management could materially impact our results of operations and financial condition. Our management has discussed this critical accounting policy and the related estimates and assumptions with the audit committee of our board of directors.

We are subject to the provisions of the Financial Accounting Standards Board (FASB) authoritative guidance issued regarding Regulated Operations. The guidance permits us to record regulatory assets and regulatory liabilities to reflect future cost recoveries or refunds, respectively, that we have a right to pass through to our members. At December 31, 2011, our regulatory assets and liabilities totaled $352 million and $164 million, respectively. While we do not currently foresee any events such as competition or other factors that would make it not probable that we will recover these costs from our members as future revenues through rates under our wholesale power contracts, if such an event were to occur, we could no longer apply the provisions of accounting for Regulated Operations, which would require us to eliminate all regulatory assets and liabilities that had been recognized as a charge to our statement of revenues and expenses and begin recognizing assets and liabilities in a manner similar to other businesses in general. In addition, we would be required to determine any impairment to other assets, including plants, and write-down those assets, if impaired, to their fair values.

New Accounting Pronouncements

In January 2010, the FASB issued Fair Value Measurements and Disclosures – Improving Disclosures about Fair Value Measurements. Effective March 31, 2011, the standard requires a reporting entity to present separately information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than a net basis) in the reconciliation for fair value measurements using significant unobservable inputs (Level 3). Our adoption of the standard did not have a material effect on our disclosures.

In April 2011, the FASB issued Fair Value Measurements: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRSs). The amendments clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and include those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The standard is effective for our fiscal year ended December 31, 2011. The adoption of the standard did not have any impact on our results of operations, cash flows or financial condition.

In May 2011, the FASB issued Comprehensive Income: Presentation of Comprehensive Income. The standard requires that an entity present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. In December 2011, the FASB issued Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05. The standard indefinitely defers the effective date of the specific requirement to present the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income on the face of the financial statements due to concerns that the requirement will be difficult for preparers and may add unnecessary complexity to financial statements. All entities should report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before May 2011. All other requirements issued in Comprehensive Income: Presentation of Comprehensive Income are effective for our fiscal year ending December 31, 2012. Our adoption of this standard will not have a material effect on our financial statements.

In December 2011, the FASB, issued "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities," which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. This guidance is effective for our fiscal year ending December 31, 2013. The adoption of this standard is not expected to have a material impact on our consolidated financial position or results of operations.

Results of Operations

Operating Revenues

Sales to Members. We generate revenues principally from the sale of electric capacity and energy.

- Capacity revenues are derived primarily from electric capacity sales to our members under the wholesale power contracts. The members have contractually agreed to pay us for the electric capacity they obtain from us to meet their operating requirements. We receive capacity revenues whether or not our generation assets, including power purchase contracts, are dispatched to produce electricity.
- Energy revenues are earned by selling electricity to our members, which involves generating or purchasing electricity for our members.

Our kilowatt-hour sales to our members, one of the primary drivers of our operating revenues, fluctuate from period to period based on several factors, including weather and other seasonal factors, load requirements in the service territories of our members, operating costs, availability of electric generation resources, our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights and by members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers.

Total revenues from sales to members decreased by 5.3% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased by 13.0% for the year ended December 31, 2010 compared to the year ended December 31, 2009. The components of member revenues were as follows:

	(dollars in thousands)		
	2011	2010	2009
Capacity revenues	**$ 685,045**	$ 677,049	$ 641,713
Energy revenues	**539,193**	615,618	502,299
Total	**$ 1,224,238**	$ 1,292,667	$ 1,144,012

Capacity revenues relate primarily to the assignment to each of the members of the fixed costs, including fixed production expenses, depreciation and amortization expenses and interest charges associated with our business. Each member is required to pay us for capacity furnished under its wholesale power contract in accordance with rates we establish.

Capacity revenues from members increased 1.2% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 5.5% for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase in capacity revenues for 2011 compared to 2010 is primarily due to cost recovery related to discontinuing preliminary construction activities at two generation projects, a combined-cycle plant and a biomass facility. The increase in capacity revenues in 2010 compared to 2009 resulted partly from an increase in operations and maintenance expenses due to higher costs incurred at Plants Hatch and Vogtle, higher depreciation expenses at Plants Scherer and Wansley related to capital expenditures for environmental compliance projects, higher net interest charges due to increased amortization of debt discount and expense for costs associated with the Hartwell acquisition and supplemental credit enhancement for Rocky Mountain, and an increase in the margins for interest ratio to 1.14 in 2010 compared to 1.12 in 2009. These increases were offset somewhat by a decrease in purchase power capacity costs attributable to the Hartwell acquisition. For further discussion regarding operation and maintenance, depreciation and amortization and purchased power, see "– *Operating Expenses;*" for further discussion regarding amortization of debt discount and expense, see "– *Interest Charges.*"

Energy revenues relate primarily to the pass-through to our members of the variable costs, such as fuel costs, variable operation and maintenance costs and purchased energy costs, associated with our business. Each member is required to pay us for energy we furnish it under its wholesale power contract, in accordance with rates we establish.

Energy revenues from members decreased 12.4% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 22.5% for the year ended December 31, 2010 compared to the year ended December 31, 2009. Energy revenues from members were lower in 2011 as compared to 2010 primarily due to lower kilowatt-hour sales to our members primarily as a result of a planned outage at Plant Scherer which resulted in lower generation available to members. In addition, lower purchased power energy costs, primarily due to the lower volume of purchased megawatt-hours, contributed to the decrease in energy costs. The increase in energy revenues for 2010 as compared to 2009 was primarily due to the pass-through of higher fuel costs associated with increased coal-fired generation at Plants Scherer and Wansley. For a discussion of fuel costs and purchased power costs, see "– *Operating Expenses.*"

The following table summarizes the kilowatt-hours sold to members and total revenues per kilowatt-hour during each of the past three years:

	(in thousands)	Cents per Kilowatt-hour
2011	**19,574,145**	**6.25**
2010	22,644,790	5.71
2009	20,191,657	5.67

For the year ended December 31, 2011 compared to the year ended December 31, 2010, kilowatt-hour sales to members decreased 13.6% and for the year ended December 31, 2010 as compared to the year ended December 31, 2009, kilowatt-hour sales to members increased 12.1%. The average revenue per kilowatt-hour from sales to members increased 9.6% and 0.7% for 2011 compared to 2010 and for 2010 compared to 2009, respectively. Decreases in kilowatt-hours of generation sold to our members and kilowatt-hours of purchased power were the reasons for decreased kilowatt-hours sold to members in 2011. An increase in kilowatt-hours of generation was the primary reason for increased kilowatt-hours sold to members in 2010. For further discussion regarding fuel and purchased power costs, see "– *Operating Expenses*."

We pass through actual energy costs to our members such that energy revenues equal energy costs. The energy portion of member revenues per kilowatt-hour increased 1.3% for the year ended December 31, 2011 as compared to the year ended December 31, 2010 and increased 9.3% for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase in average revenues per kilowatt-hour in 2010 compared to 2009 is primarily due to the pass-through of higher fuel costs. For further discussion regarding fuel costs and purchased power costs, see "– *Operating Expenses*."

Sales to Non-members. Our sales to non-members in 2011 consisted primarily of capacity and energy sales to Georgia Power under an agreement to sell the entire output of Murray Unit No. 1 through May 31, 2012. In addition we sold energy generated from Murray Unit No. 2 to non-members via the spot market. For information regarding the acquisition of Murray, see Note 12 of Notes to Consolidated Financial Statements.

Operating Expenses

Our operating expenses increased 9.2% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 14.5% for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increases over the past two years resulted primarily from higher fuel costs, production costs and depreciation and amortization, offset somewhat by lower purchased power costs.

The following table summarizes our megawatt-hour generation and fuel costs by generating source and purchased power costs.

	Year Ended December 31,					
	2011		2010		2009	
Fuel Source	**Cost (thousands)**	**Generation (Mwh)**	Cost (thousands)	Generation (Mwh)	Cost (thousands)	Generation (Mwh)
Coal	**$ 233,525**	**7,640,089**	$ 298,224	10,591,595	$ 224,395	8,337,307
Nuclear	**74,815**	**9,691,869**	65,917	10,053,614	52,163	9,504,799
Gas	**215,531**	**5,369,874**	115,360	2,343,250	81,608	2,270,638
Pumped Storage	**3,320**	**996,234**	1,878	986,192	2,246	988,969
	$ 527,191	**23,698,066**	$ 481,379	23,974,651	$ 360,412	21,101,713

	Cost (thousands)	**Purchased (Mwh)**	Cost (thousands)	Purchased (Mwh)	Cost (thousands)	Purchased (Mwh)
Purchased Power	**$ 60,590**	**287,522**	$ 78,810	417,094	$ 123,105	779,108

Total fuel costs increased 9.5% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 33.6% for the year ended December 31, 2010 as compared to the year ended December 31, 2009 while total generation decreased 1.2% and increased 13.6% for the same periods, respectively. Average fuel cost per kilowatt-hour increased 10.8% in 2011 compared to 2010 and increased 17.6% in 2010 compared to 2009. The increase in total and average fuel costs for 2011 as compared to 2010 resulted primarily from a change in the mix of generation with an increase in higher priced natural gas-fired generation of 3,027,000 megawatt-hours primarily offset by a decline in coal-fired generation of 2,952,000 megawatt-hours as well as a small decrease in nuclear generation of 362,000 megawatt-hours. The increase in natural gas-fired generation was primarily due to the Murray acquisition while the decrease in coal-fired generation was due to a scheduled outage at Plant Scherer for the installation of environmental compliance equipment and for the performance of general maintenance. The generation from Murray was utilized for non-member sales, thus there was little impact to members from generation at Murray. The increase in total and average fuel costs for 2010 as compared to 2009 resulted primarily from a 27.0% increase in higher cost coal-fired generation at Plants Scherer and Wansley. The increase in generation was due to significantly less scheduled outage time in 2010 as compared to 2009. The 2009 outages were primarily related to environmental compliance projects.

Production expenses increased 7.5% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 16.3% for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase for 2011 compared to 2010 resulted from operations and maintenance expenses at Murray, which was acquired in April 2011, and a planned major maintenance outage as well as costs incurred to repair a damaged transformer at Hawk Road. These increases were offset somewhat by lower operations and maintenance costs at Hartwell which had major maintenance outage costs in 2010. Reductions in property taxes at the jointly-owned plants helped to offset the above mentioned increases in 2011 as compared to 2010. For 2010 as compared to 2009, the increase in production expenses resulted partly from increased general operations and maintenance expenses at Plants Hatch and Vogtle and partly due to operations and maintenance expenses for Hawk Road and Hartwell. We acquired Hawk Road and Hartwell in May and October of 2009, respectively. For information regarding Hawk Road and Hartwell, see Note 12 of Notes to Consolidated Financial Statements.

Purchased power costs decreased 23.1% for the year ended December 31, 2011 as compared to the year ended December 31, 2010 and decreased 36.0% for the year ended December 31, 2010 compared to the year ended December 31, 2009. Purchased kilowatt-hours decreased 31.0% in 2011 compared to 2010 and decreased 46.5% for 2010 compared to 2009. The decrease in purchased power costs for 2011 compared to 2010 resulted from (i) lower realized losses incurred for natural gas financial contracts utilized for managing exposure to fluctuations in the market prices of natural gas and (ii) a decrease in kilowatt-hours acquired under our energy replacement program, which replaces power from our owned generation facilities with power purchased on the spot market at a lower price. The decrease in purchased power energy costs for 2010 compared to 2009 resulted from (i) a decrease in kilowatt-hours acquired under our energy replacement program, (ii) lower realized losses incurred for natural gas financial contracts and (iii) no power purchases under the Hartwell power purchase agreement in 2010 as a result of our acquisition of Hartwell in 2009. Our acquisition of Hartwell means we are now responsible for all expenses related to the operation and maintenance of the facility.

Depreciation and amortization expense increased 51.4% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 4.7% for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in depreciation and amortization in 2011 as compared to 2010 resulted primarily from depreciation at Murray. In addition, the increase in depreciation and amortization for the current year period as compared to the same prior year period was also related to amortization of costs associated with discontinued preliminary construction activities at two generation projects (a combined-cycle plant and a biomass facility) and due to higher depreciation for Plants Scherer and Wansley related to environmental compliance projects recently placed into service. The additional capital improvements at Plants Scherer and Wansley resulted in new higher depreciation rates which became effective January 1, 2011. The increase in depreciation and amortization in 2010 compared to 2009 was primarily due to increased depreciation expense for Plants Scherer and Wansley related to capital expenditures for environmental compliance projects that were placed in service during 2009. Also, depreciation expense related to Hawk Road, acquired in 2009, contributed to the increase.

Accretion expense totaled $18.2 million for the year ended December 31, 2011, $17.1 million for the year ended December 31, 2010 and $18.3 million for the year ended December 31, 2009. The accretion expense recognized under accounting for Asset Retirement Obligations, primarily relates to our nuclear generation facilities.

The effect on net margin of Murray and Hawk Road is being deferred until 2016 at which time the amounts will be amortized over the remaining life of the plants. In implementing the deferral plans, we assumed that our members would generally not require energy from the plants until 2016. If any of our members subscribed to Murray elect to take energy from Murray prior to 2016, the deferral of the effect on net margin would terminate for that member and the amortization of that member's deferral would commence immediately. The change in cost deferrals in 2011 as compared to 2010 resulted from the Murray and Hawk Road costs discussed above in production costs. For additional information regarding Murray and Hawk Road, see Note 12 of Notes to Consolidated Financial Statements.

Interest Charges

Interest on long-term debt and capital leases increased by 11.1% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 10.8% for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increases in 2011 and 2010 as compared to the same prior year periods are primarily due to the increased debt issued to finance the construction of Plant Vogtle Units No. 3 and No. 4.

Allowance for debt funds used during construction increased by 74.8% for 2011 compared to 2010 and by 115.0% for 2010 compared to 2009 primarily due to construction expenditures for Plant Vogtle Units No. 3 and No. 4.

Amortization of debt discount and expense decreased 13.3% for the year ended December 31, 2011 compared to the year ended December 31, 2010 and increased 26.5% for the year ended December 31, 2010 compared to the year ended December 31, 2009. The decrease in 2011 compared to 2010 was primarily due to the completed amortization in December 2010 of issuance costs associated with transactions that closed in May and August 2009 to provide supplemental credit enhancement for the Rocky Mountain lease arrangements. The increase in 2010 as compared to 2009 was partly due to amortization of issuance costs associated with transactions to provide supplemental credit enhancement for the Rocky Mountain lease arrangements and partly due to the amortization of losses on debt refinancings associated with the Hartwell acquisition.

Net Margin

Our net margin for the years ended December 31, 2011, 2010 and 2009 was $37.7 million, $33.7 million and $26.4 million, respectively. These amounts produced respective margins for interest ratios of 1.14, 1.14 and 1.12, each greater than the minimum required under our first mortgage indenture. Our margin requirement is based on a ratio applied to interest charges on debt secured by our first mortgage indenture. In addition, our margins include certain items that are excluded from the margins for interest ratio, such as non-cash capital credits allocation from Georgia Transmission. Our non-cash capital credits allocation from Georgia Transmission was $1.7 million for 2011, $1.7 million for 2010 and $1.5 million for 2009.

To continue to enhance our financial coverage during a period of generation facility construction and acquisition, our board of directors approved a budget for 2012 to achieve a margins for interest ratio of 1.14, above the minimum 1.10 ratio required by the first mortgage indenture. For additional information on our margin requirement, see "– Summary of Cooperative Operations – *Rates and Regulation.*" For additional information on our generation facility construction, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources."

Financial Condition

Overview

Our financial condition remains stable.

In keeping with our budgeted margin for 2011, we achieved a 1.14 margins for interest ratio which produced a net margin of $37.7 million. This increased patronage capital (our equity) and resulted in total patronage capital and membership fees of $633.7 million at December 31, 2011.

The minimum margins for interest ratio required under the first mortgage indenture is 1.10. However, to enhance margin coverage during the period of Vogtle Units No. 3 and No. 4 construction, our board of directors approved a 1.12 margins for interest ratio for 2009 and a 1.14 margins for interest ratio for 2010, 2011 and 2012. Our board of directors will continue to evaluate the level of margin coverage throughout the construction period and may choose to further increase, or decrease, the margins for interest ratio in the future.

Although we have increased our margins for interest coverage, due to the amount of new debt we issued in 2011, the majority of which relates to the Plant Vogtle construction, our equity to total capitalization ratio decreased from 10.4% at December 31, 2010 to 9.5% at December 31, 2011. While the absolute level of margins and patronage capital are increasing, our equity ratios will continue to decrease during the peak years of construction. Once the new Vogtle units are placed in-service, we expect our equity ratio to start an upward trend.

We had a strong liquidity position at December 31, 2011, with $1.7 billion of unrestricted available liquidity, including $443.7 million of cash.

Our total assets increased to $8.1 billion at December 31, 2011 from $7.0 billion at December 31,

2010. The majority of this increase relates to an increase in total utility plant in connection with the acquisition of Murray and construction of Vogtle Units No. 3 and No. 4.

We maintained adequate access to capital throughout 2011, issuing more than $480 million of long-term debt in the capital markets. We also utilized shorter-term credit arrangements, including commercial paper and a three-year bank term loan, to provide interim financing for the Plant Vogtle construction and the Murray acquisition at a very low cost. The average cost of funds on the $721 million of interim financing outstanding at December 31, 2011 was 0.7%. See "– *Financing Activities*" for a discussion of the permanent financing of these facilities.

There was a net increase in long-term debt of approximately $900 million at December 31, 2011 compared to December 31, 2010. The significant net increase in long-term debt was due to: i) the issuance of $300 million of first mortgage bonds to fund the Plant Vogtle construction, ii) $424 million of funds advanced under Rural Utilities Service-guaranteed loans during the year, and iii) a new $260 million term loan that funded a portion of the cost to acquire Murray. The weighted average interest rate on the $5.9 billion of long-term debt and capital leases outstanding at December 31, 2011 was 4.9%.

Property additions and plant acquisitions during 2011 totaled $1.4 billion and were financed with a combination of funds from operations and short-term and long-term borrowings. This includes costs related to the construction of the new Plant Vogtle units, environmental control facilities being installed at Plant Scherer, normal additions and replacements to existing generation facilities, purchases of nuclear fuel and the acquisition of Murray.

Sources of Capital and Liquidity

Sources of Capital. Our operations have historically provided a sizable contribution to the funding of capital requirements, such that internally generated funds have provided interim funding or long-term capital for nuclear fuel purchases, replacements and additions to existing generation facilities, general plant additions, and retirement of long-term debt. However, due to the significant amount of expenditures relating to environmental compliance projects underway at Plant Scherer, the construction of the new units at Plant Vogtle and the recent acquisitions of gas-fired generation, we are currently funding our capital requirements through a combination of funds generated from operations and short-term and long-term borrowings.

We have historically obtained the majority of our long-term financing from Rural Utilities Service-guaranteed loans funded by the Federal Financing Bank. However, Rural Utilities Service funding levels are uncertain and may be limited at any point in the future due to budgetary and political pressures faced by Congress. Also, the financing needs of electric cooperatives nationwide are expected to remain strong in the coming years, creating heavy demand for Rural Utilities Service funding. The President's budget proposal for fiscal year 2013, which starts on October 1, 2012, provides for $6.1 billion in loans – a reduction of less than 10% from 2012 levels. Not more than $2 billion could be made available for environmental improvements to fossil-fueled generation that would reduce emissions, with the remaining funding limited to renewable energy, transmission, distribution and carbon-capture projects on generation facilities, and low emission peaking units affiliated with energy facilities that produce electricity from solar, wind and other intermittent sources of energy. Although Congress has historically rejected proposals to dramatically curtail the Rural Utilities Service loan program, there can be no assurances that it will continue to do so. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service loans that may be available to us in the future. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with the Rural Utilities Service."

We have also obtained a substantial portion of our long-term financing requirements from the issuance of bonds in the taxable and tax-exempt capital markets, and expect to continue to access these markets in the future. However, the types of equipment that will qualify for tax-exempt financing are fewer than in the past due to changes in tax laws and regulations.

Therefore, any generation facilities that we may build or acquire in the future will likely be financed long-term through a variety of sources, which could include Rural Utilities Service-guaranteed loans funded through the Federal Financing Bank, publicly or privately offered debt financings (both taxable and tax-exempt) and other financing sources.

In connection with a loan program established pursuant to Title XVII of the Energy Policy Act of 2005, the Department of Energy has offered us a conditional term sheet under a federal loan guarantee program for up to 70% of eligible project costs, not to exceed $3.057 billion, related to our 30% participation in the two new nuclear units at Plant Vogtle.

See "– *Capital Requirements – Capital Expenditures*" for more detailed information regarding our estimated capital expenditures. See "– *Financing Activities*" for more detailed information regarding our financing plans.

Liquidity. At December 31, 2011, we had $1.7 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of $443.7 million of cash and cash equivalents and $1.2 billion of unused and available committed short-term credit arrangements.

Net cash provided by operating activities was $239 million in 2011, and averaged $292 million per year for the three year period 2009 through 2011.

At December 31, 2011, we had $1.9 billion of committed credit arrangements in place comprised of five separate facilities as reflected in the table below:

Committed Credit Facilities

(dollars in millions)

	Authorized Amount	Available 12/31/2011	Expiration Date
Unsecured Facilities:			
Syndicated Line of Credit[1]	$ 1,265	$ 668[2]	June 2015
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	33[3]	December 2013
Secured facilities:			
CoBank Line of Credit	150	150	November 2012
CFC Line of Credit	250	250	December 2013
Total	**$ 1,925**	**$ 1,211**	

(1) This credit facility is syndicated among fourteen banks led by Bank of America, as administrative agent.

(2) Of the portion of this facility that is unavailable, $461 million is dedicated to support commercial paper we have issued and $136 million relates to letters of credit issued to support variable rate demand bonds.

(3) Of the portion of this facility that is unavailable, $114 million relates to letters of credit issued to support variable rate pollution control revenue bonds and $3 million relates to letters of credit issued to post collateral to third parties.

In June 2011, we substantially restructured and upsized our primary credit facility, from the prior $475 million commercial paper line of credit to the $1.265 billion syndicated line of credit. We have the flexibility to use the syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up outstanding commercial paper.

We have been able to maintain a robust liquidity position over the last several years due to the strong relationships we have with the banks participating in our credit facilities. The syndicated line of credit facility includes fourteen participant banks as shown in the table below:

Syndicated Line of Credit Facility – Participant Banks	**Commitment** (dollars in millions)
Bank of America, N.A. – Administrative Agent	$ 210
CoBank, ACB	150
SunTrust Bank	130
Wells Fargo Bank, N.A.	125
Royal Bank of Canada	110
The Bank of Tokyo – Mitsubishi UFJ, Ltd	100
Bank of Montreal	100
Mizuho Corporate Bank, LTD.	80
JPMorgan Chase Bank, National Association	60
Fifth Third Bank	50
Goldman Sachs Bank USA	50
US Bank, National Association	50
PNC Bank, National Association	40
Chang Hwa Commercial Bank	10
Total	**$ 1,265**

Under our commercial paper program we are authorized to issue commercial paper in amounts that do not exceed the amount of any committed backup lines of credit, thereby providing 100% dedicated support for any commercial paper outstanding.

Under our committed lines of credit with JPMorgan Chase, CFC, CoBank and the syndicated line of credit, we have the ability to issue letters of credit totaling $910 million in the aggregate, of which $658 million remained available at December 31, 2011. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under the syndicated line for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue.

We are currently issuing commercial paper to provide interim funding for (i) payments to Georgia Power related to the construction of Vogtle Units No. 3 and No. 4, (ii) a portion of the cost to acquire Murray, and (iii) the upfront payments made in connection with the interest rate hedging program. For a discussion of the Plant Vogtle construction, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*." For a discussion of the Murray acquisition, see Note 12a of Notes to Consolidated Financial Statements. For a discussion of our plans regarding permanent financing for Vogtle Units No. 3 and No. 4 and the Murray acquisition, see "– *Financing Activities*." For a discussion of the interest rate hedging program, see "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK – Interest Rate Risk."

In April 2011, we closed a $260 million three-year term loan with three banks to provide interim financing for a portion of the cost of acquiring Murray. The remaining $272 million of the acquisition cost is being financed on an interim basis with commercial paper.

Between projected cash on hand and the credit arrangements currently in place, we believe we have sufficient liquidity to cover normal operations and to provide interim financing for the new Vogtle units under construction.

Several of our line of credit facilities contain similar financial covenants that require us to maintain minimum patronage capital levels. Currently, we are required to maintain minimum patronage capital of $575 million. As of December 31, 2011, our patronage capital balance was $633.7 million. An additional covenant contained in several of our credit facilities limits our secured indebtedness to $9.5 billion and unsecured indebtedness to $4.0 billion. At December 31, 2011, we had approximately $5.4 billion of secured indebtedness outstanding and $721 million of unsecured indebtedness outstanding.

Under the $250 million line of credit with National Rural Utilities Cooperative Finance Corporation (CFC), we have the option of converting any amounts outstanding under the line of credit to a term loan with a maturity no later than December 31, 2043. Any amounts drawn under this line of credit, as well as any amounts converted to a term loan, will be secured under the first mortgage indenture.

Under a power bill prepayment program we instituted in 2008, members can prepay their power bills from us at a discount for an agreed number of months in advance, after which point the funds are credited against the participating members' monthly power bills. The discount is comparable to our avoided cost of borrowing. Since the program began, we have received a total of $372 million in power bill prepayments from nineteen members who have participated in the program, including $64.8 million in 2011. At December 31, 2011, the balance remaining to be applied against future power bills was $102.3 million.

In addition to unrestricted available liquidity, at December 31, 2011 we had $107.3 million of restricted liquidity including $106.7 million in restricted short-term investments pursuant to deposits made into a Rural Utilities Service Cushion of Credit Account. The deposits in the Cushion of Credit Account were made voluntarily and earn a guaranteed rate of interest of 5% per annum. The funds in the account, including interest thereon, can only be applied to debt service on Rural Utilities Service notes and Rural Utilities Service-guaranteed Federal Financing Bank notes. From time to time we may deposit additional funds into the Cushion of Credit Account.

Liquidity Covenants. At December 31, 2011, we had only one financial agreement in place containing a liquidity covenant. This covenant is in connection with the Rocky Mountain lease transactions and requires us to maintain minimum liquidity of $50 million at all times during the term of the lease. We had sufficient liquidity to meet this covenant in 2011 and expect to have sufficient liquidity to meet this covenant in 2012.

Financing Activities

First Mortgage Indenture. Our first mortgage debt is secured equally and ratably under the first mortgage indenture by a lien on substantially all of our tangible and some of our intangible assets, including those we acquire in the future. The mortgaged property includes our electric generating plants and some of our contracts for the purchase, sale or transmission of electricity of more than one year in duration or that relate to the ownership, operation, construction or maintenance of our electric generation facilities. Murray, which we acquired in 2011, is currently owned by one of our wholly-owned subsidiaries and not directly by us. Consequently, Murray is not currently included in the mortgaged property; however, we anticipate that it will become part of the mortgaged property later in 2012.

Indenture for Unsecured Debt Securities. In 2010, we put in place an indenture for unsecured debt securities to provide an additional financing alternative. Its most likely use would be to finance certain indirect costs related to the construction or acquisition of new generation facilities. We have no debt securities outstanding under the unsecured indenture currently, although we are evaluating plans to issue debt under this indenture later in 2012.

Bond Financings. In March 2011, the Development Authorities of Appling County, Burke County and Monroe County, Georgia issued, on our behalf, $180.4 million of variable rate tax-exempt pollution control revenue bonds for the purpose of refunding $180.4 million of pollution control bonds issued by the development authorities on our behalf in 1992, 2007 and 2008. This tax-exempt debt is secured under the first mortgage indenture.

In August 2011, we issued $300 million of fixed rate first mortgage bonds. The bonds were issued for the purpose of financing a portion of the cost of constructing Vogtle Units No. 3 and No. 4 and to redeem commercial paper issued in connection with this construction. These bonds are secured under the first mortgage indenture.

We have a program under which we have refinanced, on a continued tax-exempt basis, the annual principal maturities of pollution control bonds originally issued on our behalf by the Development Authority of Monroe County, Georgia. The refinancing of these pollution control bonds' principal maturities allows us to preserve a low-cost source of financing. To date, we have refinanced approximately $300 million under this program. As part of a tax-exempt refinancing we plan to close in April 2012, we will refinance the final $10.1 million principal maturity under this program.

In April 2012, we are planning to close on a $32.4 million financing transaction that includes two components. In one component the Development Authority of Monroe County will issue, on our behalf, $10.1 million of term rate pollution control revenue bonds for the purpose noted above. This tax-exempt debt will be secured under the first mortgage indenture. The second component entails a remarketing of $22.3 million of pollution control bonds issued previously on our behalf by the Development Authority of Burke County due to a mandatory tender of these bonds which were originally issued in a term rate period that ends on March 31, 2012.

Rural Utilities Service-Guaranteed Loans. We currently have six approved Rural Utilities Service-guaranteed loans, funded through the Federal Financing Bank, totaling $1.7 billion that are in various stages of being drawn down, with $1.1 billion remaining to be advanced. Included in the six approved loans are two loans that were approved in 2011. One loan approved in 2011 is for general improvements at existing facilities and the other loan relates to the Murray acquisition.

Although the President's budget proposal for fiscal year 2013 would prohibit Rural Utilities Service funding for fossil-fueled generation unless the funding relates to environmental improvements, we will continue to submit loan applications for such facilities to the extent Rural Utilities Service regulations in place at the time we submit the applications allow us to do so, including loan applications for any additional gas-fired facilities our members may subscribe to. See "BUSINESS – OUR POWER SUPPLY RESOURCES – *Other Future Power Resources*" for a discussion of member interest in new gas-fired capacity. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with the Rural Utilities Service" for a discussion of the Rural Utilities Service's current position relating to funding of new generation facilities.

All of the approved Rural Utilities Service loans will be funded through the Federal Financing Bank and guaranteed by the Rural Utilities Service, and the debt will be secured under our first mortgage indenture.

Department of Energy-Guaranteed Loan. The Department of Energy loan guarantee program was authorized pursuant to Title XVII of the Energy Policy Act of 2005, which is intended to support innovative technologies to reduce air pollutants, including greenhouse gases. Pursuant to this program, in May 2010 we signed a conditional term sheet with the Department of Energy that sets forth the general terms of a loan and related loan guarantee that would fund 70% of the estimated $4.2 billion cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4, not to exceed $3.057 billion. The loan structure would entail a loan that is funded by the Federal Financing Bank carrying a federal loan guarantee provided by the Department of Energy, with the debt secured under our first mortgage indenture.

Final approval and issuance of a loan guarantee by the Department of Energy is subject to negotiation of definitive agreements, completion of due diligence by the Department of Energy and satisfaction of other conditions. Therefore, there can be no assurance that the Department of Energy will ultimately issue the loan guarantee to us. We anticipate that any Plant Vogtle costs not funded under the Department of Energy loan guarantee program would be financed through the issuance of taxable bonds.

Of the approximately $1.2 billion of currently estimated project costs not expected to be funded under the Department of Energy loan guarantee program, we have already financed $1.15 billion through the issuance of first mortgage bonds.

Capital Requirements

Capital Expenditures. As part of our ongoing capital planning, we forecast expenditures required for generating facilities and other capital projects. The table below details these forecasts for 2012 through 2014. Actual expenditures may vary from the estimates listed in the table because of factors such as changes in business conditions, design changes and rework required by regulatory bodies, delays in obtaining necessary regulatory approvals, construction delays, changing environmental requirements, and changes in cost of capital, equipment, material and labor.

Capital Expenditures[(1)]
(dollars in millions)

	2012	2013	2014	Total
Future Generation[(2)]	$ 487	$ 860	$ 634	$ 1,981
Existing Generation[(3)]	127	107	115	349
Environmental Compliance[(4)]	181	134	104	419
Nuclear Fuel[(5)]	124	119	135	378
General Plant	4	6	4	14
Total	$ 923	$ 1,226	$ 992	$ 3,141

(1) Includes allowance for funds used during construction.
(2) Relates to construction of Vogtle Units No. 3 and No. 4, excluding initial nuclear fuel core.
(3) Normal additions and replacements to plant in-service
(4) Pollution control equipment being installed at Plants Scherer and Wansley.
(5) Includes nuclear fuel on existing nuclear units and initial nuclear fuel core for Vogtle Units No. 3 and No. 4.

In addition to the amounts reflected in the table above, we expect to incur capitalized costs of approximately $678 million by 2017 to complete construction of Vogtle Units No. 3 and No. 4. For information about steps we have taken to procure financing for the Plant Vogtle project, see "– *Financing Activities.*"

We are currently subject to extensive environmental regulations and may be subject to future additional environmental regulations, including future implementation of existing laws and regulations. Since alternative legislative and regulatory environmental compliance programs continue to be debated on a national level, particularly in relation to climate change, it is difficult to predict what capital costs may ultimately be required.

Environmental compliance projects currently underway include the installation of flue gas desulfurization equipment and a selective catalytic reduction system at Plant Scherer, both expected to be in-service by 2014. In addition, a project to reduce mercury emissions at Plant Wansley may commence later in 2012, and if built, is expected to be in-service by 2016. The capital expenditures for this mercury emissions project are included in the table above. Assuming we move forward with this project, we expect to spend an additional approximately $40 million to complete this project beyond the years reflected in the capital expenditure table above.

Depending on how we and the other co-owners of Plants Wansley and Scherer choose to comply with any future legislation or regulations, both capital expenditures and operating expenditures may be impacted. As required by the wholesale power contracts, we expect to be able to recover from our members all capital and operating expenditures made in complying with current and future environmental regulations.

For additional information regarding environmental regulation, see "BUSINESS – ENVIRONMENTAL AND OTHER REGULATION."

Contractual Obligations. The table below reflects, as of December 31, 2011, our contractual obligations for the periods indicated.

Contractual Obligations
(dollars in millions)

	2012	2013-2014	2015-2016	Beyond 2016	Total
Long-Term Debt:					
Principal(1)	$ 128	$ 581	$ 361	$ 4,623	$ 5,693
Interest(2)	300	532	521	3,709	5,062
Capital Leases(3)	59	65	51	82	257
Operating Leases	6	11	9	12	38
Rocky Mtn.Lease Transactions(4)	–	–	–	372	372
Chattahoochee O&M Agmts.	22	45	47	46	160
Asset Retirement Obligations(5)	–	–	–	2,168	2,168
Total	**$ 515**	**$ 1,234**	**$ 989**	**$ 11,012**	**$ 13,750**

(1) Includes principal amounts that would be due if the credit support facilities for the 2009 and 2010 pollution control bonds were drawn upon and became payable in accordance with their terms. These amounts are $75 million in 2013, $37 million in 2014 and $134 million in 2015. To date, none of these credit support facilities have been drawn upon for principal and we anticipate extending these facilities before their expiration. The nominal maturities of the 2009 and 2010 pollution control bonds range from 2030 through 2038.

(2) Includes interest expense related to variable rate debt. Future variable rates are based on projected LIBOR and SIFMA interest rate curves as of February 2012.

(3) Amounts represent total rental payment obligations, not amortization of debt underlying the leases.

(4) We entered into Equity Funding Agreements for a third party to fund this obligation. For additional information, see "*– Off-Balance Sheet Arrangements – Rocky Mountain Lease Arrangements.*"

(5) A substantial portion of this amount relates to the decommissioning of nuclear facilities.

Rate Matters

We have made available to our members two rate management programs that allow us to expense and recover certain costs on a current basis that would otherwise be capitalized. The subscribing members in Murray and Vogtle Units No. 3 and No. 4 can elect to participate in one, both or neither of these two programs on an annual basis.

The Murray program allows for the accelerated recovery of deferred net costs related to Murray. The Murray program became effective December 31, 2011 and the amount expensed and billed to members in 2011 was not material. Members representing 35%, or approximately $15 million, of projected net costs in 2012 have elected to participate in the Murray program.

The Vogtle program allows for the recovery of financing costs associated with the construction of Vogtle Units No. 3 and No. 4 on a current basis. This program became effective January 1, 2012. Members representing 12.3%, or approximately $9 million, of projected interest during construction in 2012 have elected to participate in this program.

Any effect of these rate management programs on our financial statements is subject to annual member elections to participate.

Inflation

As with utilities generally, inflation has the effect of increasing the cost of our operations and construction program. Operating and construction costs have been less affected by inflation over the last few years because rates of inflation have been relatively low. While we cannot predict what level of inflation may occur in the future, in light of current U.S. financial policies, the potential for inflationary pressures exist.

Credit Rating Risk

The table below sets forth our current ratings from Standard & Poor's, Moody's Investors Service and Fitch Ratings.

Our Ratings	S&P	Moody's	Fitch
Long-term ratings:			
Senior secured rating(1)	A	Baa1	A
Issuer rating	A	Baa2	n/r(2)
Rating outlook	Stable	Stable	Stable
Short-term rating:			
Commercial paper rating	A-1	P-2	F1

(1) We currently have no unsecured ratings assigned to any of our long-term debt.

(2) n/r indicates no rating assigned for this rating category

We have financial and other contractual agreements in place containing provisions which, upon a credit rating downgrade below specified levels, may require the posting of collateral in the form of letters of credit or other acceptable collateral. Our primary exposure to potential collateral postings is at rating levels of BBB-/Baa3 or below. As of December 31, 2011, our maximum potential collateral requirements were as follows:

At senior secured rating levels:

- a total of approximately $50 million at a senior secured level of BBB-/Baa3,
- a total of approximately $236 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured or issuer rating levels:

- a total of approximately $50,000 at a senior unsecured or issuer rating level of BBB-/Baa3,

- a total of approximately $5.0 million at a senior unsecured or issuer rating level of BB+/Ba1 or below.

The Rural Utilities Service Loan Contract contains covenants that, upon a credit rating downgrade below investment grade by two rating agencies, could result in restrictions on issuing debt. Certain of our pollution control bond agreements contain provisions based on the ratings assigned to the bonds (which could be related to either our rating or a bond insurer's rating if the bonds are insured) that, upon a credit rating downgrade below specified levels, could result in increased interest rates. Also, borrowing rates and commitment fees in all of our line of credit agreements are based on credit ratings and could increase if our ratings are lowered. None of these covenants and provisions, however, would result in acceleration of any debt due to credit rating downgrades.

Given our current level of ratings, our management does not have any reason to expect a downgrade that would result in credit ratings below the rating triggers contained in any of our financial and contractual agreements. However, our ratings reflect only the views of the rating agencies, and therefore we cannot give any assurance that our ratings will be maintained at current levels for any period of time.

Off-Balance Sheet Arrangements

We are liable for certain contractual obligations for which other parties are primarily liable, and we would be expected to pay only if the other parties fail to satisfy such obligations. These obligations are not shown on our balance sheet and are described below.

Georgia Transmission Debt Assumption. In connection with our corporate restructuring in 1997 in which we sold our transmission related assets to Georgia Transmission (which represented 16.86% of our assets), Georgia Transmission assumed 16.86% of the then outstanding indebtedness associated with pollution control bonds pursuant to an assumption agreement and an indemnity agreement. If Georgia Transmission fails to satisfy its obligations under this debt assumption, we remain liable for any unsatisfied amounts. In that event, we would be entitled to reimbursement from Georgia Transmission for any amounts we paid. At January 1, 2011, the total joint obligation debt assumed by Georgia Transmission relating to outstanding pollution control bond principal was $94.5 million. On April 1, 2011, Georgia Transmission refunded $54.3 million of this debt and, as a result, only $40.2 million of joint obligation debt remains. On April 2, 2012, Georgia Transmission plans to refund the remaining $40.2 million of this debt, and assuming the plan is carried out, at that point there will no longer be any assumed joint obligation debt outstanding.

Rocky Mountain Lease Arrangements. In December 1996 and January 1997, we entered into six long-term lease transactions relating to our 74.61% undivided interest in Rocky Mountain. In each transaction, we leased a portion of our undivided interest in Rocky Mountain to six separate owner trusts (referred to as the head leases) for the benefit of three investors (referred to as owner participants) for a term equal to 120% of the estimated useful life of Rocky Mountain, in exchange for one-time rental payments aggregating $794 million made at the time the leases were entered into. Each owner participant, through its related owner trust, funded a portion of its payment to us through an equity contribution (in the aggregate totaling $171 million), and financed the remaining portion through a loan from a bank. Immediately following the head leases to the owner trusts, the owner trusts leased their undivided interests in Rocky Mountain to our wholly owned subsidiary, Rocky Mountain Leasing Corporation (RMLC), for a term of 30 years under six separate leases, referred to as the facility leases. RMLC then subleased the undivided interests back to us for an identical term also under six separate leases, referred to as the facility subleases.

We used a portion of the one-time rental payments paid to us by the owner trusts to acquire the capital stock of RMLC and to make a $698 million capital contribution to RMLC. RMLC in turn used the capital contribution to fund six payment undertaking agreements (in the aggregate totaling $641 million) with Rabobank Nederland (referred to as the payment undertaker) and six equity funding agreements (in the aggregate totaling $57 million) with AIG Matched Funding Corp. that provide for these third parties to pay all of:

- RMLC's periodic basic rent payments under the facility leases; and
- the fixed purchase price of the undivided interests in Rocky Mountain at the end of the terms of the facility leases if we cause RMLC to exercise its option to purchase these interests at that time.

As a result of these lease transactions, after making the capital contribution to RMLC, we had $92 million remaining of the amount paid by the owner trusts which we used to prepay Federal Financing Bank indebtedness while retaining possession of, and entitlement to, our portion of the output of Rocky Mountain.

The facility subleases require us to make semi-annual rental payments to RMLC. In turn, RMLC is required to make identical rental payments to the owner trusts under the facility leases. In 2011, the amount of the rental payments under the facility subleases and facility leases each totaled $58 million. The payment undertaking agreements require the payment undertaker to pay the rent payments directly to the owner trust's lender in satisfaction of RMLC's rent payment obligation under the facility leases and the applicable owner trust's repayment obligation under the loans used to finance a portion of the one-time rental payments to us described above. Because RMLC funds these rent payments through the payment undertaking agreements, RMLC returns to us, in the form of a patronage dividend, amounts received by it pursuant to the facility subleases other than amounts RMLC requires to fund its annual operating expenses. RMLC remains liable for all rental payments under the facility leases (and would not be able to make such patronage dividend to us) if the payment undertaker fails to make such payments, although the owner trusts have agreed to use due diligence to pursue the payment undertaker before pursuing payment from RMLC or us.

The senior unsecured debt obligations of Rabobank are rated AA by S&P and Aaa by Moody's. RMLC has the right to replace Rabobank as the payment undertaker with substitute credit protection of certain approved governmental or other entities, including banks or financial institutions rated at least AA by S&P and Aa2 by Moody's; provided that any replacement therefore is subject to approval by the owner participants in accordance with their internal credit policies and guidelines. If, as a result of replacing the payment undertaker, the lender requests a higher interest rate on the loans, RMLC will be required to find a replacement lender to purchase the loan certificates from the lender unless the owner participants consent to such increase in the interest rate.

AIG Matched Funding Corp. is a wholly owned subsidiary of American International Group, Inc. (AIG) and AIG has guaranteed the obligations of AIG Matched Funding Corp. under the equity funding agreements. At the time the lease transactions were entered into, AIG's senior unsecured debt obligations were rated AAA by S&P and Aaa by Moody's. The equity funding agreements provide that if AIG fails to maintain a credit rating of at least AA from S&P and Aa2 from Moody's, then AIG Matched Funding Corp. will be required to post collateral having a stipulated credit quality to secure its obligations thereunder.

In September 2008, AIG's ratings fell below the collateralization threshold. As a result, AIG Matched Funding Corp. posted collateral in compliance with the equity funding agreements, consisting of securities issued by an instrumentalities of the United States government that are rated AAA in an amount equal to 105% of the net present value of its future payment obligations related to the equity portion of the fixed purchase price (equity portion of the fixed purchase price was $132 million at December 31, 2011). In accordance with the terms of the equity funding agreements, the market value of the posted collateral (other than cash) is determined weekly by an independent third party and AIG Matched Funding Corp. is required to post additional collateral to the extent that it is determined that the market value of such collateral, together with the cash collateral (if any), has fallen below the required collateral amount as discussed above. According to U.S. Bank National Association, which as collateral agent holds the collateral and provides the weekly valuation thereof, the market value of the collateral was $141 million at December 31, 2011.

If AIG fails to comply with its collateralization obligations or fails to maintain a credit rating of at least BBB- from S&P and Baa3 from Moody's, then RMLC must, within 60 days of becoming aware of such fact, enter into replacement equity funding agreements with a financial institution that has credit ratings of at least AA from S&P and Aa2 from Moody's. If such replacement is triggered by AIG's failure to provide sufficient collateral, RMLC would have the right to terminate the equity funding agreements at the higher of market value or accreted value (as determined in each case). However, if AIG is rated below BBB- from S&P and below Baa3 from Moody's, but AIG Matched Funding Corp. is in compliance with its collateralization requirement, RMLC would not have a right to terminate the equity funding agreements in connection with a replacement. AIG's ratings are currently A- from S&P and Baa1 from Moody's. In the event that RMLC is not able to enter into replacement equity funding agreements, then RMLC may be required to purchase the owner trusts' equity interests from the owner participants.

The operative agreements relating to the Rocky Mountain lease transactions also require us to maintain surety bonds with a surety bond provider that meets minimum credit rating requirements to secure certain of our payment obligations under the Rocky Mountain lease transactions. Accordingly, we entered into a surety bond arrangement with AMBAC Assurance Corporation concurrently with the consummation of the Rocky Mountain lease transactions.

The operative agreements relating to the Rocky Mountain lease transactions provide that if the surety bond provider fails to maintain a credit rating of at least AA from S&P or Aa2 from Moody's, then we must, within 60 days of becoming aware of such fact, provide (i) a replacement surety bond from a surety bond provider that has such credit ratings, (ii) a letter of credit from a bank with such credit ratings, (iii) other acceptable credit enhancement or (iv) any combination thereof. In the event that we are unable to obtain replacement credit enhancement, then we may be required to purchase the owner trusts' equity interests from the owner participants.

In November 2008, AMBAC's credit ratings fell below the minimum threshold, triggering our obligation to provide replacement credit enhancement. In two separate transactions that closed in May 2009 (relating to five of the leases) and in August 2009 (relating to the sixth lease), we entered into agreements with Berkshire Hathaway Assurance Corporation pursuant to which Berkshire is providing supplemental credit enhancement to the credit enhancement provided by AMBAC, thereby satisfying our obligation to provide replacement credit enhancement.

Berkshire is currently rated AA+ by S&P and Aa1 by Moody's. As with AMBAC, if Berkshire is downgraded below AA by S&P and Aa2 by Moody's, we will be obligated to replace, within 60 days of becoming aware of that fact, the Berkshire surety bonds for all six of the lease transactions with other qualified credit enhancement. With regard to the sixth lease transaction only, we have an obligation to replace Berkshire surety bonds with other qualified credit enhancement if (i) federal legislation is enacted which imposes a tax on reimbursement payments that may be owed to Berkshire by either us or AMBAC under this lease transaction, and (ii) Berkshire elects to terminate its surety bond in connection with the enactment of such legislation. During 2009, legislation of the type referred to above was introduced in each of the House of Representatives and Senate. If this or similar legislation is enacted, Berkshire would have a right to terminate its surety bond in the sixth lease transaction but not in any of the other five lease transactions. This would in turn trigger our obligation to provide replacement credit enhancement within 60 days for the sixth lease transaction. The enactment of this legislation would make it difficult for us to find other qualified credit enhancement.

As our wholly owned subsidiary, the financial condition and results of operations of RMLC are fully consolidated into our financial statements. The equity funding agreements and corresponding lease obligations are reflected on our balance sheets as Deposit on Rocky Mountain transactions and Obligation under Rocky Mountain transactions ($132 million at December 31, 2011 and $124 million at December 31, 2010). However, our financial statements do not reflect the payment undertaking agreements or the corresponding lease obligations, or the payments made by the payment undertaker, including the payments of rent under the facility leases and facility subleases, because they have been extinguished for financial reporting purposes. If RMLC's interests in the payment undertaking agreements and the corresponding lease obligations were reflected on our balance sheets at December 31, 2011, both the Deposit on Rocky Mountain transactions and Obligation under Rocky Mountain transactions would have been higher by $708 million. However, it would have no effect on our statements of operations or cash flows.

The assets of RMLC, including the payment undertaking agreements and the equity funding agreements, are not available to pay our creditors or our affiliates' creditors.

At the end of the term of each facility lease, we have the option to cause RMLC to purchase any owner trust's undivided interests in Rocky Mountain at fixed purchase option prices that aggregate $1.087 billion for all six facility leases. The payment undertaking agreements and equity funding agreements would fund $715 million and $372 million of this amount, respectively, and these amounts would be paid to the owner trusts over five installments in 2027. If we do not elect to cause RMLC to purchase any owner trust's undivided interest in Rocky Mountain, Georgia Power has an option to purchase that undivided interest. If neither we nor Georgia Power exercise our purchase option, and we return (through RMLC) any undivided interest in Rocky Mountain to an owner trust, that owner trust has several options it can elect, including:

- causing RMLC and us to renew the related facility leases and facility subleases for up to an additional 16 years and provide collateral satisfactory to the owner trusts,
- leasing its undivided interest to a third party under a replacement lease, or
- retaining the undivided interest for its own benefit.

Under the first two of these options we must arrange new financing for the outstanding amount of the loans used to finance the owner trusts' one-time rental payments described above. The aggregate amount of the outstanding loans to all of the owner trusts at the end of the term of the facility leases is anticipated to be $666 million. If new financing cannot be arranged, the owner trusts can ultimately cause us to purchase 49%, in the case of the first option above, or all, in the case of the second option above, of the loan certificates or cause RMLC to exercise its purchase option or RMLC and us to renew the facility leases and facility subleases, respectively.

If option one above is chosen, at the end of the 16-year lease renewal term, the facility leases and facility subleases terminate, the owner trusts take possession of Rocky Mountain at whatever its value and operating condition may be at such time, with no residual value guaranty.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Due to our cost-based rate structure, we have limited exposure to market risks. However, changes in interest rates, equity prices, and commodity prices may result in fluctuations in member rates. We use derivatives only to manage this volatility and do not use derivatives for speculative purposes.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in July 2010 could impact our use of over-the-counter derivatives. 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.

For additional information regarding our rate structure, see "BUSINESS – OGLETHORPE POWER CORPORATION – Electric Rates."

We have an executive risk management and compliance committee that provides general oversight over corporate compliance and all risk management activities, including, but not limited to, commodity trading, fuels management, insurance procurement, debt management, investment portfolio management, environmental compliance, and electric reliability compliance. This committee is comprised of our chief executive officer, chief operating officer, chief financial officer and the executive vice president, member and external relations. The risk management and compliance committee has implemented comprehensive risk management policies to manage and monitor credit, market price, and other corporate risks. These policies also specify controls and authorization levels related to various risk management activities. The committee frequently meets to review corporate exposures, risk management strategies, hedge positions, and compliance matters. The audit committee of our board of directors receives regular reports on corporate exposures, risk management activities and the actions of the risk management committee. For further discussion of our board of director's oversight of risk management, see "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE – Board of Directors' Role in Risk Oversight."

Interest Rate Risk

At December 31, 2011, we were exposed to the risk of changes in interest rates related to our $1.3 billion of variable rate debt, which includes $461 million of commercial paper outstanding (which typically has maturities of between 1 and 90 days) and $571 million of pollution control bond debt outstanding (including weekly rate bonds, auction rate securities subject to repricing every 35 days and term rate bonds subject to repricing from March 2012 through March 2013). At December 31, 2011, the weighted average interest rate on this variable rate debt was 0.9%. If, during 2012, interest rates on this debt changed a hypothetical 100 basis points on the respective repricing dates and remained at that level for the remainder of the year, annual interest expense would change by approximately $11 million.

Our objective in managing interest rate risk is to maintain a balance of fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. As part of this debt management strategy we have a general guideline of having between 15% and 30% variable rate debt to total debt. At December 31, 2011, we had 21% of our total debt, including commercial paper and capital lease debt, in a variable rate mode.

The operative documents underlying the pollution control bond debt contain provisions that allow us to convert the debt to a variety of variable interest rate modes (such as daily, weekly, monthly, commercial paper, or term rate mode), or to convert the debt to a fixed rate of interest to maturity. Having these interest rate conversion options improves our ability to manage our exposure to variable interest rates.

In addition to interest rate risk on existing debt, we are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Plant Vogtle Units No. 3 and No. 4. We have entered into a conditional term sheet with the Department of Energy to finance up to $3.057 billion of the cost to construct the new Vogtle units. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Financing Activities – Department of Energy-Guaranteed Loans*." The term sheet provides for quarterly draws from 2012 through 2017 and interest rates that will be based on U.S. Treasury rates at the time of each draw, plus a fixed spread. To mitigate the risk of rising interest rates, in the fourth quarter of 2011, we hedged a portion of our interest rate risk related to the financing of the new Vogtle units. Under this program, we made upfront premium payments of $100 million to purchase interest rate options to hedge the interest rates on approximately $2.2 billion of the Department of Energy-guaranteed loan, representing a substantial portion of the expected borrowings from 2013 through 2017. Expected borrowings in 2012 were not hedged.

The interest rate options we purchased, commonly known as LIBOR swaptions, give us the future right, but not the obligation, to enter into a swap in which we would pay a fixed rate and receive a floating LIBOR rate. However, the swaptions are required to be cash settled based on their value on the expiration date before any payments on the underlying swap are actually made. As a result, the swaptions effectively cap our interest rates by offsetting the present value cost of an increase in interest rates above the fixed rate. The cash settlement value depends on the extent to which prevailing LIBOR swap rates exceed the fixed rate on the underlying swap, and the value would be zero if swap rates are at or below the fixed rate upon expiration. The fixed rates on the LIBOR swaptions we purchased are in the range of 100 to 200 basis points above current LIBOR swap rates and the weighted average fixed rate is 4.17%. The swaptions' expiration dates are timed to match the expected quarterly draw dates of the Department of Energy-guaranteed loan advances to be hedged; however, as the swaptions' value is independent from the Department of Energy-guaranteed loan, the swaptions could also serve as a hedge of interest rates on an alternative source of financing.

We paid the entire premium at the time we entered into these swaption transactions and have no additional payment obligations. However, upon expiration of the swaptions, each counterparty will be obligated to pay us the cash value of the swaption, if any. In order to diversify counterparty risk, we entered into these transactions with six large banks with average ratings ranging from A- to AA. To manage our credit exposure to these counterparties, the agreements we have with the counterparties contain support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the swaptions outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from $0 to $10 million depending on each counterparty's credit rating.

We expect to defer any gains or losses from the change in fair value of each swaption and related carrying and other incidental costs. The deferred costs, which are not expected to exceed $135 million, and deferred gains, if any, from the sale or settlement of the swaptions will then be amortized and collected in rates over the expected life of the Department of Energy-guaranteed loan.

Capital Leases

We entered into a power purchase and sale agreement with Doyle I, LLC to purchase all of the output from a five-unit gas-fired generation facility. The Doyle agreement is reported on our balance sheet as a capital lease. The lease payments vary to the extent the interest rate on the lessor's debt varies from 6.00%. At December 31, 2011, the weighted average interest rate on the lease obligation was 5.86%.

Equity Price Risk

We maintain external trust funds (reflected as "Nuclear decommissioning trust fund" on the balance sheet) to fund our share of certain costs associated with the decommissioning of our nuclear plants as required by the Nuclear Regulatory Commission (see Note 1 of Notes to Consolidated Financial Statements). We also maintain an internal reserve for decommissioning (included in "Long-term investments" on the balance sheet) from which funds can be transferred to the external trust fund, if necessary.

The allocation of equity and fixed income securities in both the external and internal funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs; however, the equity portion of these funds is exposed to price fluctuations in equity markets, and the values of fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the investment performance of the funds and periodically review asset allocation in accordance with our nuclear decommissioning fund investment policy. Our investment policy establishes targeted and permissible investment allocation ranges for equity and fixed income securities. The targeted asset allocation is diversified among various asset classes and investment styles. Specific investment guidelines are established with each of the investment advisors that are selected to manage a particular asset class or subclass.

The investment guidelines for equity securities typically limit the type of securities that may be purchased and the concentration of equity holdings in any one issuer and within any one sector. With respect to fixed-income securities, the investment guidelines set forth limits for the type of bonds that may be purchased, state that investments be primarily in securities with an assigned investment grade rating of BBB- or above and establish that the average credit quality of the portfolio typically be A+/A1 or higher.

A 10% decline in the value of the internal and external funds' equity securities as of December 31, 2011 would result in a loss of value to the funds of approximately $17 million. For further discussion on our nuclear decommissioning trust funds, see Note 1 of Notes to Consolidated Financial Statements.

Commodity Price Risk

Coal

We are also exposed to the risk of changing prices for fuels, including coal and natural gas. We have interests in 1,501 megawatts of coal-fired nameplate capacity at Plants Scherer and Wansley. We purchase coal under term contracts and in spot-market transactions. Some of our coal contracts provide volume flexibility and most have fixed or capped prices. We anticipate that our existing contracts and stockpiles will provide fixed prices for nearly 100% of our remaining forecasted coal requirements for 2012 and fixed or capped prices for approximately 70% of our forecasted coal requirements in 2013.

The objective of our coal procurement strategy is to ensure reliable coal supply and some price stability for our members. Our strategy focuses on coal commitments for up to 7 years. The procurement guidelines provide for layering in fixed and/or capped prices by annually entering into coal contracts for a portion of projected coal need for up to 7 years.

Natural Gas

We own five gas-fired generation facilities totaling approximately 3,136 megawatts of nameplate capacity. See "PROPERTIES – Generating Facilities."

We also have a power purchase contract with Doyle I, LLC (treated as a capital lease) under which approximately 325 megawatts of nameplate capacity and associated energy is supplied by gas-fired facilities. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Power Purchase and Sale Arrangements – *Power Purchases*" and "PROPERTIES – Generating Facilities." Under this contract, we are exposed to variable energy charges, which incorporate the facility's actual operation and maintenance and fuel costs. We have the right to purchase natural gas for Doyle and exercise this right to actively manage the cost of energy supplied from this contract and the underlying natural gas price and operational risks.

In providing operation management services for Smarr EMC, we purchase natural gas, including transportation and other related services, on behalf of Smarr EMC and ensure that the Smarr facilities have fuel available for operations. See "BUSINESS – OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources" and "PROPERTIES – Generating Facilities" and "– Fuel Supply."

We manage exposure to fluctuations in the market price of natural gas for 13 of our members who have elected to participate in our natural gas hedging program. This program layers in fixed prices over a rolling eight-quarter time horizon using natural gas swap arrangements for a portion of the forecasted gas requirements related to the gas-fired resources that we manage and/or operate. Under these swap agreements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment. If the natural gas swaps had been terminated on December 31, 2011, we would have made a net payment of approximately $7.2 million. As of December 31, 2011, approximately 10% of our 2012 total system forecasted natural gas requirements (including requirements for the Smarr facilities) were hedged under swap arrangements. A hypothetical 10% decline in the market price of natural gas would have resulted in a decrease of approximately $2.1 million to the fair value of our natural gas swap agreements. Effective April 1 of each year, additional members may elect to participate in our natural gas hedging program.

Members may choose to discontinue receiving these natural gas price management services at any time.

Changes in Risk Exposure

Our exposure to changes in the price of equity securities we hold, commodity prices, and changes in interest rates on existing variable rate debt has not changed materially from the previous reporting period. We have reduced our exposure to the risk of rising interest rates on approximately $2.2 billion of the future long-term debt we expect to incur in connection with the Plant Vogtle construction by purchasing interest rate options, as described above.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index To Financial Statements

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF REVENUES AND EXPENSES
For the years ended December 31, 2011, 2010 and 2009

	(dollars in thousands)		
	2011	2010	2009
Operating revenues:			
Sales to Members	**$ 1,224,238**	$ 1,292,667	$ 1,144,012
Sales to non-Members	**166,040**	1,478	1,249
Total operating revenues	**1,390,278**	1,294,145	1,145,261
Operating expenses:			
Fuel	**527,191**	481,379	360,412
Production	**357,069**	332,236	285,654
Depreciation and amortization	**199,040**	131,491	125,600
Purchased power	**60,590**	78,810	123,105
Accretion	**18,249**	17,131	18,261
Deferral of Hawk Road and Murray Energy facilities effect on net margin	**(9,681)**	13,849	8,107
Total operating expenses	**1,152,458**	1,054,896	921,139
Operating margin	**237,820**	239,249	224,122
Other income:			
Investment income	**29,496**	30,208	31,825
Amortization of deferred gains	**5,660**	5,660	5,660
Allowance for equity funds used during construction	**2,904**	2,417	2,394
Other	**6,204**	5,366	2,849
Total other income	**44,264**	43,651	42,728
Interest charges:			
Interest expense	**296,138**	266,641	240,743
Allowance for debt funds used during construction	**(72,692)**	(41,593)	(19,345)
Amortization of debt discount and expense	**20,901**	24,119	19,062
Net interest charges	**244,347**	249,167	240,460
Net margin	**$ 37,737**	$ 33,733	$ 26,390

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2011 and 2010

	(dollars in thousands)	
	2011	2010
Assets		
Electric plant:		
In service	**$ 7,335,866**	$ 6,672,253
Less: Accumulated provision for depreciation	**(3,328,585)**	(3,101,731)
	4,007,281	3,570,522
Nuclear fuel, at amortized cost	**284,205**	249,563
Construction work in progress	**1,784,264**	1,195,475
Total electric plant	**6,075,750**	5,015,560
Investments and funds:		
Nuclear decommissioning trust fund	**268,597**	265,483
Deposit on Rocky Mountain transactions	**132,048**	123,573
Investment in associated companies	**57,626**	56,125
Long-term investments	**80,055**	79,212
Restricted cash	**43,070**	–
Other, at cost	**3,564**	3,570
Total investments and funds	**584,960**	527,963
Current assets:		
Cash and cash equivalents	**443,671**	672,212
Restricted cash	**613**	6,300
Restricted short-term investments	**106,676**	97,286
Receivables	**124,650**	106,674
Inventories, at average cost	**246,795**	171,815
Prepayments and other current assets	**15,562**	13,416
Total current assets	**937,967**	1,067,703
Deferred charges and other assets		
Deferred debt expense, being amortized	**67,470**	59,202
Regulatory assets	**351,547**	311,136
Other	**61,135**	15,498
Total deferred charges	**480,152**	385,836
Total assets	**$ 8,078,829**	$ 6,997,062

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2011 and 2010

	(dollars in thousands)	
	2011	2010
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 633,689**	$ 595,952
Accumulated other comprehensive margin (deficit)	**618**	(469)
	634,307	595,483
Long-term debt	**5,562,925**	4,657,127
Obligations under capital leases	**146,781**	179,288
Obligation under Rocky Mountain transactions	**132,048**	123,573
Total capitalization	**6,476,061**	5,555,471
Current liabilities:		
Long-term debt and capital leases due within one year	**172,818**	170,947
Short-term borrowings	**461,093**	305,959
Accounts payable	**134,095**	139,614
Accrued interest	**91,106**	76,435
Accrued and withheld taxes	**21,118**	27,171
Members power bill prepayments, current	**66,819**	71,496
Other current liabilities	**25,080**	18,567
Total current liabilities	**972,129**	810,189
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**26,113**	28,587
Asset retirement obligations	**298,758**	280,496
Member power bill prepayments, non-current	**35,500**	41,000
Power sale agreement, being amortized	**54,816**	69,480
Regulatory liabilities	**164,000**	170,235
Other	**51,452**	41,604
Total deferred credits and other liabilities	**630,639**	631,402
Total equity and liabilities	**$ 8,078,829**	$ 6,997,062
Commitments and Contingencies (Notes 1, 5, 9, 11 and 12)		

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2011 and 2010

(dollars in thousands)	2011	2010
Long-term debt:		
Mortgage notes payable to the Federal Financing Bank at interest rates varying from 2.70% to 8.43% (average rate of 5.01% at December 31, 2011) due in quarterly installments through 2043	**$ 2,125,149**	$ 1,784,611
Mortgage notes payable to National Rural Utilities Cooperative Finance Corporation at interest rates varying from 3.00% to 4.90% (average rate of 4.07% at December 31, 2011) due in quarterly installments through 2020	**7,388**	8,026
Mortgage bonds payable:		
• Series 2006 Term Bonds, 5.534%, due 2031 through 2035	**300,000**	300,000
• Series 2007 Term Bonds, 6.191%, due 2024 through 2031	**500,000**	500,000
• Series 2009A Term Bonds, 6.10%, due 2019	**350,000**	350,000
• Series 2009B Term Bonds, 5.95%, due 2039	**400,000**	400,000
• Series 2009 Clean renewable energy bond, 1.81%, due 2024	**13,134**	14,145
• Series 2010A Term bonds, 5.375% due 2040	**450,000**	450,000
• Series 2011A Term bonds, 5.25% due 2050	**300,000**	–
Mortgage notes issued in connection with the sale of pollution control revenue bonds through the Development Authorities of Appling, Burke, Heard and Monroe County, Georgia:		
• Series 1992A Monroe Serial bonds, 6.80%, due through 2012	**10,371**	20,082
• Series 2003A Burke, Heard, Monroe and 2003B Burke Auction rate bonds, 0.44%, due 2024	**95,230**	95,230
• Series 2004 Burke and Monroe Auction rate bonds, 0.41%, due 2020	**11,525**	11,525
• Series 2005 Burke and Monroe Auction rate bonds, 0.44%, due 2040	**15,865**	15,865
• Series 2007A Appling and Monroe, 2007B Appling and Burke, 2007C through F Burke Term rate bonds, fully redeemed April 2011	**–**	131,649
• Series 2008A through C Burke Fixed rate bonds, 5.30% to 5.70%, due 2032 through 2043	**255,035**	255,035
• Series 2008E Burke Fixed rate bonds, 7.00%, due 2020 through 2023	**144,750**	144,750
• Series 2008F Burke and 2008A Monroe Term rate bonds, fully redeemed April 2011	**–**	41,125
• Series 2008G Burke Term rate bonds, 6.75% through March 31, 2012, due 2039	**22,325**	22,325
• Series 2009A Heard and Monroe, and 2009B Monroe Weekly rate bonds, 0.07% to 0.08%, due 2030 through 2038	**112,055**	112,055
• Series 2010A Burke and Monroe, and 2010B Burke Weekly rate bonds, 0.12%, due 2036 through 2037	**133,550**	133,550
• Series 2011A Burke and Monroe, and 2010B Burke Weekly rate bonds, 0.12%, due 2036 through 2037	**180,380**	–
CoBank, ACB notes payable:		
• Transmission mortgage note payable: variable at an average rate of 2.19% through January 29, 2012, due in bimonthly installments through November 1, 2018	**1,125**	1,223
• Transmission mortgage note payable: variable at an average rate of 2.18% through January 29, 2012, due in bimonthly installments through September 1, 2019	**4,621**	4,958
Total Secured Long-term, net	**$ 5,432,503**	$ 4,796,154
Bank term loan		
Notes payable: variable at 1.53% through January 12, 2012, due April 2014	**260,000**	–
Total long-term debt	**$ 5,692,503**	$ 4,796,154
Obligations under capital leases	**191,900**	212,561
Obligation under Rocky Mountain transactions	**132,048**	123,573
Patronage capital and membership fees	**633,689**	595,952
Accumulated other comprehensive margin (deficit)	**618**	(469)
Subtotal	**6,650,758**	5,727,771
Less: long-term debt and capital leases due within one year	**(172,818)**	(170,947)
Less: unamortized bond discounts on long-term debt	**(1,879)**	(1,353)
Total capitalization	**$ 6,476,061**	$ 5,555,471

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2011, 2010 and 2009

	(dollars in thousands)		
	2011	2010	2009
Cash flows from operating activities:			
Net margin	**$ 37,737**	$ 33,733	$ 26,390
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	**321,715**	250,723	225,423
Accretion cost	**18,249**	17,131	18,261
Amortization of deferred gains	**(5,660)**	(5,660)	(5,660)
Allowance for equity funds used during construction	**(2,904)**	(2,417)	(2,394)
Deferred outage costs	**(56,358)**	(25,911)	(35,464)
Deferral of Hawk Road and Murray Energy facilities effect on net margin	**(9,681)**	13,849	8,107
Loss (gain) on sale of investments	**(14,915)**	(14,239)	6,938
Regulatory deferral of costs associated with nuclear decommissioning	**5,089**	5,480	(18,465)
Other	**(10,598)**	(9,022)	(5,021)
Change in operating assets and liabilities:			
Receivables	**(8,456)**	(7,299)	1,064
Inventories	**(40,774)**	38,022	(29,703)
Prepayments and other current assets	**(2,146)**	(4,023)	(3,480)
Accounts payable	**8,617**	(729)	(1,876)
Accrued interest	**14,671**	25,488	16,408
Accrued and withheld taxes	**(6,362)**	2,307	5,996
Other current liabilities	**542**	791	6,639
Member power bill prepayments	**(10,177)**	(88,018)	195,514
Total adjustments	**200,852**	196,473	382,287
Net cash provided by operating activities	**238,589**	230,206	408,677
Cash flows from investing activities:			
Property additions	**(839,503)**	(669,206)	(627,148)
Plant acquisitions	**(530,293)**	–	(274,251)
Activity in nuclear decommissioning trust fund – Purchases	**(1,068,979)**	(608,542)	(635,081)
– Proceeds	**1,063,277**	603,600	630,055
(Increase) decrease in restricted cash and cash equivalents	**(37,383)**	16,105	(12,150)
Increase in restricted short-term investments	**(9,390)**	(16,696)	(80,590)
Decrease (increase) in investment in associated organizations	**472**	(599)	(9,033)
Activity in other long-term investments – Purchases	**(2,469)**	(6,822)	(1,963)
– Proceeds	**1,100**	18,524	2,600
Activity on interest rate options – Purchases	**(100,000)**	–	–
– Collateral received	**43,070**	–	–
Other	**(10,726)**	3,421	(3,944)
Net cash used in investing activities	**(1,490,824)**	(660,215)	(1,011,505)
Cash flows from financing activities:			
Long-term debt proceeds	**1,163,593**	740,124	992,246
Long-term debt payments	**(288,722)**	(240,185)	(110,905)
Increase in short-term borrowings	**155,135**	22,325	143,634
Other	**(6,312)**	888	(10,737)
Net cash provided by financing activities	**1,023,694**	523,152	1,014,238
Net (decrease) increase in cash and cash equivalents	**(228,541)**	93,143	411,410
Cash and cash equivalents at beginning of period	**672,212**	579,069	167,659
Cash and cash equivalents at end of period	**$ 443,671**	$ 672,212	$ 579,069
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	**$ 196,629**	$ 187,958	$ 193,897
Supplemental disclosure of non-cash investing and financing activities:			
Change in plant expenditures included in accounts payable	**$ (7,848)**	$ 138,898	$ (969)

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

OGLETHORPE POWER CORPORATION

CONSOLIDATED STATEMENTS OF PATRONAGE CAPITAL AND MEMBERSHIP FEES AND ACCUMULATED OTHER COMPREHENSIVE MARGIN (DEFICIT)

For the years ended December 31, 2011, 2010 and 2009

	(dollars in thousands)		
	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Margin (Deficit)	Total
Balance at December 31, 2008	$ 535,829	$ (1,348)	$ 534,481
Components of comprehensive margin in 2009			
Net margin	26,390	–	26,390
Unrealized gain on available-for-sale securities	–	95	95
Total comprehensive margin			26,485
Balance at December 31, 2009	562,219	(1,253)	560,966
Components of comprehensive margin in 2010			
Net margin	33,733	–	33,733
Unrealized gain on available-for-sale securities	–	784	784
Total comprehensive margin			34,517
Balance at December 31, 2010	595,952	(469)	595,483
Components of comprehensive margin in 2011			
Net margin	37,737	–	37,737
Unrealized gain on available-for-sale securities	–	1,087	1,087
Total comprehensive margin			38,824
Balance at December 31, 2011	$ 633,689	$ 618	$ 634,307

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

1. Summary of significant accounting policies:

a. Business description

Oglethorpe Power Corporation is an electric membership corporation incorporated in 1974 and headquartered in metropolitan Atlanta, GA. We are owned by 39 retail electric distribution cooperative members in Georgia. The wholesale electric power we provide consists of a combination of generating units totaling 6,844 megawatts of nameplate capacity. Our members in turn distribute energy on a retail basis to approximately 4.1 million people.

In December 2009, Flint EMC became our 39th member. Flint did not have a percentage capacity responsibility from any of our generation resources in 2011; however, it has the right to participate in any future generation resources we may acquire or construct.

b. Basis of accounting

Our consolidated financial statements include our accounts and the accounts of our majority-owned and controlled subsidiaries. We have determined that there are no accounts of variable interest entities for which we are the primary beneficiary. We have eliminated any intercompany profits and transactions in consolidation.

We follow generally accepted accounting principles in the United States. We maintain our accounts in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission as modified and adopted by the Rural Utilities Service. We also apply the accounting provisions for Regulated Operations.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of December 31, 2011 and 2010 and the reported amounts of revenues and expenses for each of the three years in the period ended December 31, 2011. Actual results could differ from those estimates.

c. Patronage capital and membership fees

We are organized and operate as a cooperative. Our members paid a total of $195 in membership fees. Patronage capital includes retained net margin. Any excess of revenue over expenditures from operations is treated as advances of capital by our members and is allocated to each of them on the basis of their fixed percentage capacity costs responsibilities in our generation and purchased power resources.

Any distributions of patronage capital are subject to the discretion of our board of directors, subject to first mortgage indenture requirements. Under the first mortgage indenture, we are prohibited from making any distribution of patronage capital to our members if, at the time of or after giving effect to, (i) an event of default exists under the indenture, (ii) our equity as of the end of the immediately preceding fiscal quarter is less than 20% of our total long-term debt and equities, or (iii) the aggregate amount expended for distributions on or after the date on which our equity first reaches 20% of our total long-term debt and equities exceeds 35% of our aggregate net margins earned after such date. This last restriction, however will not apply if, after giving effect to such distribution, our equity as of the end of the immediately preceding fiscal quarter is not less than 30% of our long-term debt and equities.

d. Accumulated comprehensive margin (deficit)

The table below provides detail regarding the beginning and ending balance for each classification of other comprehensive margin (deficit) along with the amount of any reclassification adjustments included in net margin for each of the years presented in the Statement of Patronage Capital and Membership Fees and Accumulated Other Comprehensive Margin

(Deficit). Our effective tax rate is zero; therefore, all amounts below are presented net of tax.

Accumulated Other Comprehensive Margin (Deficit)

	(dollars in thousands) Available-for-sale Securities
Balance at December 31, 2008	$ (1,348)
Unrealized gain	95
Balance at December 31, 2009	(1,253)
Unrealized gain	784
Balance at December 31, 2010	(469)
Unrealized gain	1,087
Balance at December 31, 2011	**$ 618**

e. Margin policy

We are required under the first mortgage indenture to produce a margins for interest ratio of at least 1.10. For the years 2011, 2010 and 2009, we achieved a margins for interest ratio of 1.14, 1.14 and 1.12, respectively.

f. Operating revenues

Operating revenues from sales to members consist primarily of electricity sales pursuant to long-term wholesale power contracts which we maintain with each of our members. These wholesale power contracts obligate each member to pay us for capacity and energy furnished in accordance with rates we establish. Electricity revenues are recognized when capacity and energy are provided. Energy provided is determined based on meter readings which are conducted at the end of each month. Actual energy costs are compared, on a monthly basis, to the billed energy costs, and an adjustment to revenues is made such that energy revenues are equal to actual energy costs.

Operating revenues from sales to non-members consist primarily of capacity and energy sales to Georgia Power Company under an agreement to sell the entire output of Murray Unit No. 1 through May 31, 2012, which was acquired in April 2011. In addition, we sold energy generated at Murray Unit No. 2 to non-members. For further discussion of the Murray Energy Facility acquisition, see Note 12a.

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2011, 2010 and 2009:

	2011	2010	2009
Cobb EMC	**12.5%**	14.5%	15.0%
Jackson EMC	**10.9%**	11.6%	11.6%
Sawnee EMC	**n/a(1)**	10.6%	10.2%

(1) In 2011, Sawnee accounted for less than 10% of our total operating revenues.

In 2011, the Rural Utilities Service approved a rate change that permitted us to implement two rate management programs that allow us to expense and recover certain costs on a current basis that would otherwise be capitalized. The subscribing members of Murray and/or Plant Vogtle Units No. 3 and No. 4, can elect to participate in one, both or neither of these two plans on an annual basis. The Murray program allows for the accelerated recovery of deferred net costs related to Murray. The Murray program became effective December 31, 2011 and the amount expensed and billed to members in 2011 was immaterial. The Vogtle program allows for the recovery of financing costs associated with the construction of Plant Vogtle Units No. 3 and No.4 on a current basis. This program became effective January 1, 2012.

g. Receivables

A substantial portion of our receivables are related to electricity sales to our members. The receivables are recorded at the invoiced amount and do not bear interest. Our members are required through the wholesale power contracts to reimburse us for all costs. The remainder of our receivables is primarily related to transactions with affiliated companies, electricity sales to non-members and to interest income on investments. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible.

h. Nuclear fuel cost

The cost of nuclear fuel, including a provision for the disposal of spent fuel, is being amortized to fuel expense based on usage. The total nuclear fuel expense for 2011, 2010 and 2009 amounted to approximately $74,814,000, $65,916,000, and $52,163,000, respectively.

Contracts with the U.S. Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at Plants Hatch and Vogtle. The Department of Energy failed to begin disposing of spent fuel in January 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants, is pursuing legal remedies against the Department of Energy for breach of contract. An on-site dry storage facility for Plant Hatch is operational and can be expanded to accommodate spent fuel through the life of the plant. Sufficient storage capacity is available at Plant Vogtle in the spent fuel pools to maintain full core discharge capacity for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units No.1 and No.2 is expected to begin in sufficient time to maintain pool full-core discharge capability.

On July 9, 2007, the U.S. Court of Federal Claims found in favor of Southern Company and awarded damages in the amount of $59,900,000 for Plant Hatch and Plant Vogtle. Our share of the award is $17,980,000. The decision has been appealed by the Department of Energy. No amounts have been recognized in the financial statements as of December 31, 2011. The final outcome of this matter cannot be determined at this time. Our rate-making treatment of any such future award received would be passed on to our members.

i. Asset retirement obligations

The accounting and reporting for asset retirement obligations are done under the authoritative guidance related to asset retirement obligations. The liability recognized primarily relates to our nuclear facilities. We also recognized retirement obligations for ash ponds, landfill sites, asbestos removal and gypsum.

Under the accounting provisions for Regulated Operations, we record an offsetting regulatory asset or liability to reflect the difference in timing of recognition of the costs of decommissioning for financial statement purposes and for ratemaking purposes. We estimate an annual decrease of approximately $800,000 over the next several years to the regulatory asset. For information regarding the regulatory asset for asset retirement obligations, see Note 1s.

Accounting for asset retirement obligations does not permit non-regulated entities to accrue future retirement costs associated with long-lived assets for which there are no legal obligations to retire. In accordance with regulatory treatment of these costs, we continue to recognize the retirement costs for these other obligations in depreciation rates. For information regarding accumulated retirement costs for other obligations, see Note 1s.

In December 2009, we obtained revised asset retirement obligations studies associated with decommissioning at Plants Hatch and Vogtle. The studies were based on the completed plant decommissioning cost estimates and were in accordance with the standards defined in the accounting guidance related to asset retirement obligations. The 2009 studies resulted in a change in the cash flow estimates of nuclear decommissioning costs as noted in the following table.

The following tables reflect the details of the Asset Retirement Obligations included in the balance sheets for the years 2011 and 2010.

(dollars in thousands)

	Balance at 12/31/10	Liabilities Incurred (Settled)	Accretion	Change in Cash Flow Estimate	**Balance at 12/31/11**
Nuclear decommissioning	$ 272,197	$ –	$ 17,616	$ –	**$ 289,813**
Other	8,299	13	633	–	**8,945**
Total	$ 280,496	$ 13	$ 18,249	$ –	**$ 298,758**

(dollars in thousands)

	Balance at 12/31/09	Liabilities Incurred (Settled)	Accretion	Change in Cash Flow Estimate	Balance at 12/31/10
Nuclear decommissioning	$ 255,654	$ –	$ 16,543	$	**$ 272,197**
Other	8,981	(1,201)	588	(69)	**8,299**
Total	$ 264,635	$ (1,201)	$ 17,131	$ (69)	**$ 280,496**

j. Nuclear decommissioning trust fund

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. We have established external trust funds to comply with the Nuclear Regulatory Commission's regulations. The funds set aside for decommissioning are managed by unrelated third party investment managers with the discretion to buy, sell and invest pursuant to investment objectives and restrictions set forth in agreements entered into between us and the investment managers. The funds are invested in a diversified mix of equity and fixed income securities. We have limited oversight of the day-to-day management of the fund investments.

We record the investment securities held in the nuclear decommissioning trust fund, which are classified as available-for-sale, at fair value, as disclosed in Note 2. Because day-to-day investment decisions are made by third party investment managers, the ability to hold investments in unrealized loss positions is outside our control. Unrealized gains and losses of the nuclear decommissioning trust fund that would be recorded in earnings or other comprehensive margin (deficit) by a non-regulated entity are directly deducted from or added to the regulatory asset for asset retirement obligations in accordance with our rate-making treatment. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset.

Nuclear decommissioning cost estimates are based on site studies and assume prompt dismantlement and removal of both the radiated and non-radiated portions of the plant from service. Actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in regulatory requirements, changes in technology, and changes in costs of labor, materials and equipment. Information with respect to our portion of the estimated costs of decommissioning co-owned nuclear facilities is as follows:

	(dollars in thousands)			
	Hatch Unit No. 1	Hatch Unit No. 2	Vogtle Unit No. 1	Vogtle Unit No. 2
Year of site study	2009	2009	2009	2009
Expected start date of decommissioning	2034	2038	2047	2049
Estimated costs based on site study:				
In year 2009 dollars	$ 164,000	$ 213,000	$ 165,000	$ 209,000

We have not collected any provision for decommissioning during the years 2011, 2010 and 2009 because the balance in the decommissioning trust fund at December 31, 2011 is expected to be sufficient to fund the nuclear decommissioning obligation in future years. In projecting future costs, the escalation rate for labor, materials and equipment was assumed to be 2.4%. We assume a 6.0% earnings rate for our decommissioning trust fund assets. Since inception (1990) to 2011, the nuclear decommissioning trust fund has produced an average annualized return of approximately 7.0%. Notwithstanding the results of the revised site studies, our management believes that any increase in cost estimates of decommissioning can be recovered in future rates.

k. Depreciation

Depreciation is computed on additions when they are placed in service using the composite straight-line method. The depreciation rates for steam and nuclear below, reflect revised rates from new 2011 depreciation rate studies. Annual depreciation rates, as approved by the Rural Utilities Service, in effect in 2011, 2010 and 2009 were as follows:

	Range of Useful Life in years*	**2011**	2010	2009
Steam production	49-65	**1.88%**	1.56%	1.52%
Nuclear production	37-60	**1.45%**	1.50%	1.90%
Hydro production	50	**2.00%**	2.00%	2.00%
Other production	27-33	**2.74%**	2.60%	3.00%
Transmission	36	**2.75%**	2.75%	2.75%
General	3-50	**2.00-33.33%**	2.00-33.33%	2.00-33.33%

* Calculated based on the composite depreciation rates in effect for 2011.

Depreciation expense for the years 2011, 2010 and 2009 was $182,905,000, $144,715,000, and $133,235,000, respectively

l. Electric plant

Electric plant is stated at original cost, which is the cost of the plant when first dedicated to public service, plus the cost of any subsequent additions. Cost includes an allowance for the cost of equity and debt funds used during construction. For the years ended 2011, 2010 and 2009, the allowance for funds used during construction rates were 5.55%, 5.73% and 5.54%, respectively.

Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are charged to expense. Replacements and renewals of items considered to be units of property are charged to the plant accounts. At the time properties are disposed of, the original cost, plus cost of removal, less salvage of such property, is charged to the accumulated provision for depreciation.

m. Cash and cash equivalents

We consider all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents. Temporary cash investments with maturities of more than three months are classified as other short-term investments.

n. Restricted cash

At December 31, 2011, we had restricted cash totaling $43,683,000 of which $43,070,000 was classified as long-term. The long-term restricted cash balance at December 31, 2011 consisted of funds posted as collateral by counterparties to our interest rate options. See Note 2 for a discussion of our interest rate options. The current portion of restricted cash at December 31, 2011 and 2010 primarily consisted of clean renewable energy bond proceeds on deposit with CoBank to fund a qualifying project at the Rocky Mountain Pumped Storage Hydroelectric facility.

o. Restricted short-term investments

At December 31, 2011 and 2010, we had $106,676,000 and $97,286,000, respectively, on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted funds will be utilized for future Rural Utilities Service/Federal Financing Bank debt service payments. The deposit earns interest at a Rural Utilities Service-guaranteed rate of 5% per annum.

p. Inventories

We maintain inventories of fossil fuels and spare parts for our generation plants. These inventories are stated at weighted average cost on the accompanying balance sheets.

The spare parts inventories primarily include the direct cost of generating plant spare parts. Spare parts are charged to inventory when purchased and then expensed or capitalized, as appropriate, when installed. The spare parts inventory is carried at weighted average cost and the parts are charged to expense or capital at weighted average cost. The fossil fuel inventories primarily include the direct cost of coal and related transportation charges. The cost of fossil fuel inventories is carried at weighted average cost and is charged to fuel expense as consumed based on weighted average cost.

At December 31, 2011 and 2010, fossil fuels inventories were $94,872,000 and $54,348,000, respectively. Inventories for spare parts at December 31, 2011 and 2010 were $151,923,000 and $117,467,000, respectively.

q. Deferred charges and other assets

We account for debt issuance costs as deferred debt expense. Deferred debt expense is amortized to expense on a straight-line basis over the life of the respective debt issues, which approximates the effective interest rate method. As of December 31, 2011, the remaining amortization periods for debt issuance costs range from approximately 1 to 39 years.

r. Deferred credits and liabilities

We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. At December 31, 2011, member power bill prepayments as reflected on the consolidated balance sheets, including unpaid discounts, were $102,319,000, of which, $66,819,000 is classified as a current liability and $35,500,000 as deferred credits and other liabilities. The prepayments are being applied against members' power bills through November 2017, with the majority of the remaining balance scheduled to be applied by the end of 2012.

In conjunction with the Hawk Road acquisition in May 2009, we recorded a liability for the assumed power sale agreement, which is being amortized over the remaining life of the agreement which ends in 2015. For further discussion of the Hawk Road acquisition, see Note 12b.

s. Regulatory assets and liabilities

We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery from our members in future revenues through rates under the wholesale power contracts with our members extending through December 31, 2050. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from members.

The following regulatory assets and (liabilities) are reflected on the accompanying balance sheets as of December 31, 2011 and 2010:

	(dollars in thousands) 2011	2010
Regulatory Assets:		
Premium and loss on reacquired debt	**$ 98,538**	$ 111,570(a)
Amortization on capital leases	**46,627**	64,561(b)
Outage costs	**42,866**	23,796(c)
Interest rate swap termination fees	**21,316**	25,306(d)
Asset retirement obligations	**29,341**	15,699(e)
Depreciation expense	**51,209**	52,632(f)
Deferred charges related to Plant Vogtle Units 3 and 4 training costs	**17,602**	9,707(g)
Interest rate options cost	**30,735**	– (h)
Other regulatory assets	**13,313**	7,865(i)
Total Regulatory Assets	**$ 351,547**	$ 311,136
Regulatory Liabilities:		
Accumulated retirement costs for other obligations	**$ 32,687**	$ 39,205(e)
Net benefit of Rocky Mountain transactions	**47,783**	50,965(j)
Deferral of effects on net margin- Hawk Road and Murray Energy facilities	**15,811**	21,956(k)
Major maintenance sinking fund	**28,524**	28,500(l)
Deferred debt service adder	**37,586**	27,678(m)
Other regulatory liabilities	**1,609**	1,931(i)
Total Regulatory Liabilities	**$ 164,000**	$ 170,235
Net regulatory assets	**$ 187,547**	$ 140,901

(a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt amortized over the period of the refunding debt, which range up to 39 years.

(b) See Note 4 under "Capital Leases." Recovered over the remaining life of the leases through 2021.

(c) Consists of both coal-fired and nuclear refueling outage costs. Coal-fired outage costs are amortized on a straight-line basis to expense over an 18 to 24-month period. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 to 24-month operating cycles of each unit.

(d) Represents amount paid on settled interest rate swaps arrangements that are being amortized over the remaining life of the refunded variable rate bonds or 2016 and 2019, respectively.

(e) See Note 1i under "Asset retirement obligations" for a discussion of the asset retirement obligation deferral and recovery and retirement costs for other obligations.

(f) Prior to NRC approval of a 20 year license extension for Plant Vogtle, we deferred the difference between Plant Vogtle depreciation expense based on the then 40-year operating license and depreciation expense assuming an expected 20-year license extension. Amortization commenced upon NRC approval of the license extension in 2009 and is being amortized over the remaining life of the plant.

(g) Plant Vogtle Units No. 3 and No. 4 training and interest related carrying costs of such training. Amortization will commence effective with the commercial operation date of each unit which is expected to be 2016 and 2017, respectively and amortized over the life of the units.

(h) Deferral of net loss (gains) associated with the change in fair value of the interest rate options to hedge interest rates on a portion of expected borrowings related to Plant Vogtle Units No.3 and No.4 construction. Amortization will commence effective with the expected principal repayment of the DOE-guaranteed loan in 2017 and amortized over the expected remaining life of DOE-guaranteed loan which will finance the construction project.

(i) The amortization period for other regulatory assets range up to 36 years and the amortization period of other regulatory liabilities range up to 8 years.

(j) Net benefit associated with Rocky Mountain lease transactions is amortized to income over the 30-year lease-back period. For a discussion of Rocky Mountain lease, see Note 2.

(k) Effects on net margin for Hawk Road and Murray will be deferred until the end of 2015 and amortized over the remaining life of each plant. For a discussion of Hawk Road and Murray, see Note 12.

(l) Represents collections for future major maintenance costs that will offset by deferred revenues when incurred.

(m) Collections to fund debt payments in excess of depreciation expense through the end of 2025; deferred revenues will be amortized over the remaining useful life of the plants.

t. Other income

The components of other income within the Consolidated Statement of Revenues and Expenses were as follows:

	(dollars in thousands) 2011	2010	2009
Capital credits from associated companies (Note 2)	**$ 2,095**	$ 2,096	$ 1,921
Net revenue from Georgia Transmission and Georgia System Operations for shared Administrative and General costs	**4,071**	3,834	1,375
Miscellaneous other	**38**	(564)	(447)
Total	**$ 6,204**	$ 5,366	$ 2,849

u. Presentation

Certain prior year amounts have been reclassified to conform with the current year presentation.

v. New accounting pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued Fair Value Measurements and Disclosures – Improving Disclosures about Fair Value Measurements. Effective March 31, 2011, the standard requires a reporting entity to present separately information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than a net basis) in the reconciliation for fair value measurements using significant unobservable inputs (Level 3). Our adoption of the standard did not have a material effect on our disclosures.

In April 2011, the FASB issued Fair Value Measurements: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRSs). The amendments clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and include those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The standard is effective for our fiscal year ended December 31, 2011. The adoption of the standard did not have any impact on our results of operations, cash flows or financial condition.

In May 2011, the FASB issued Comprehensive Income: Presentation of Comprehensive Income. The standard requires that an entity present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. In December 2011, the FASB issued Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05. The standard indefinitely defers the effective date of the specific requirement to present the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income on the face of the financial statements due to concerns that the requirement will be difficult for preparers and may add unnecessary complexity to financial statements. All entities should report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before May 2011. All other requirements issued in Comprehensive Income: Presentation of Comprehensive Income are effective for our fiscal year ending December 31, 2012. Our adoption of this standard will not have a material effect on our financial statements.

In December 2011, the FASB, issued ''Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities,'' which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. This guidance is effective for our fiscal year ending December 31, 2013. The adoption of this standard is not expected to have a material impact on our consolidated financial position or results of operations.

2. Financial instruments:

Authoritative guidance regarding fair value measurements for financial and non-financial assets and liabilities defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles, and expands disclosures about fair value measurements.

The guidance establishes a three-tier fair value hierarchy which prioritizes the inputs used in measuring fair value as follows:

- *Level 1.* Quoted prices from active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Quoted prices in active markets provide the most reliable evidence of fair value and are used to measure fair value whenever available. Level 1 primarily consists of financial instruments that are exchange-traded.
- *Level 2.* Pricing inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 2 primarily consists of financial instruments that are non-exchange-traded but have significant observable inputs.
- *Level 3.* Pricing inputs that include significant inputs which are generally less observable from objective sources. These inputs may include internally developed methodologies that result in management's best estimate of fair value. Level 3 financial instruments are those whose fair value is based on significant unobservable inputs.

As required by the guidance, assets and liabilities measured at fair value are based on one or more of the following three valuation techniques:

(1) *Market approach.* The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities (including a business) and deriving fair value based on these inputs.

(2) *Income approach.* The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

(3) *Cost approach.* The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). This approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset or comparable utility adjusted for obsolescence.

The table below details assets and liabilities measured at fair value on a recurring basis for the periods ending December 31, 2011 and 2010, respectively.

		Fair Value Measurements at Reporting Date Using			
	December 31, 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
		(dollars in thousands)			
Decommissioning funds:					
Domestic equity	**$ 102,285**	$ 102,285	$ –	$ –	(1)
International equity	**39,618**	39,618	–	–	(1)
Corporate bonds	**41,338**	–	41,338	–	(1)
U.S. Treasury and government agency securities	**41,697**	41,697	–	–	(1)
Agency mortgage and asset backed securities	**28,519**	–	28,519	–	(1)
Derivative instruments	**(982)**	–	–	(982)	(3)
Other	**16,122**	16,122	–	–	(1)
Bond, reserve and construction funds	**2,720**	2,720	–	–	(1)
Long-term investments	**80,055**	72,342	–	7,713[(1)]	(1) (3)
Interest rate options	**69,446[(2)]**	–	–	69,446	(3)
Natural gas swaps	**(7,220)**	–	(7,220)	–	(1)

		Fair Value Measurements at Reporting Date Using			
	December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Valuation Technique
		(dollars in thousands)			
Decommissioning funds					
Domestic equity	$ 105,523	$ 105,523	$ –	$ –	(1)
International equity	43,619	43,619	–	–	(1)
Corporate bonds	53,847	–	53,847	–	(1)
U.S. Treasury and government agency securities	47,649	47,649	–	–	(1)
Agency mortgage and asset backed securities	7,926	–	7,926	–	(1)
Derivative instruments	(452)	–	–	(452)	(3)
Other	7,371	7,371	–	–	(1)
Bond, reserve and construction funds	2,815	2,815	–	–	(1)
Long-term investments	79,212	70,541	–	8,671[(1)]	(1) (3)
Natural gas swaps	(2,054)	–	(2,054)	–	(1)

(1) Represents auction rate securities investments we hold.

(2) Interest rate options as reflected on the Consolidated Balance Sheet includes the fair value of the interest rate options offset by $43,070,000 of collateral received by the counterparties at December 31, 2011.

The following tables present the changes in Level 3 assets measured at fair value on a recurring basis during the years ended December 31, 2011 and 2010, respectively.

	Year Ended December 31, 2011		
	Decommissioning funds	Long-term investments	Interest rate options
	(dollars in thousands)		
Assets:			
Balance at December 31, 2010	$ (452)	$ 8,671	$ –
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets)	(530)	142	(30,554)
Impairment included in other comprehensive deficit			
Purchases, issuances, liquidations		(1,100)	100,000
Balance at December 31, 2011	**$ (982)**	**$ 7,713**	**$ 69,446**

	Year Ended December 31, 2010	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets:		
Balance at December 31, 2009	$ (260)	$ 27,010
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(192)	–
Impairment included in other comprehensive deficit	–	661
Purchases, issuances, liquidations	–	(19,000)
Balance at December 31, 2010	$ (452)	$ 8,671

The assets included in the ''Long-term investments'' column in each of the Level 3 tables above are auction rate securities. As a result of market conditions, including the failure of auctions for the auction rate securities in which we invested, the fair value of these auction rate securities was determined using an income approach based on a discounted cash flow model. The discounted cash flow model utilized projected cash flows at current rates, which was adjusted for illiquidity premiums based on discussions with market participants. At December 31, 2011, we held auction rate securities with maturity dates ranging from November 1, 2044 to December 1, 2045.

In 2010, we sold $19,000,000 of our auction rate securities which resulted in a loss of $475,000. Also in 2010, we had a temporary impairment on our auction rate securities of $1,029,000. Based on the fair value of the auction rate securities held at December 31, 2011, we recorded a ($142,000) incremental adjustment to the temporary impairment. The temporary impairment is reflected in ''Accumulated other comprehensive margin (deficit)'' on the consolidated balance sheets. The various assumptions we utilized to determine the fair value of our auction rate securities investments will vary from period to period based on the prevailing economic conditions. A 25 basis point increase in the illiquidity premium used to determine the fair value of these investments at December 31, 2011, would have resulted in an additional decrease in the fair value of our auction rate securities investments by approximately $503,000.

These investments were rated A3 by Moody's Investors Service and AAA by Fitch as of December 31, 2011. On February 15, 2012, we sold the remaining $8,600,000 of auction rate securities we held at December 31, 2011, which resulted in a loss of $1,075,000.

The estimated fair values of our long-term debt at December 31, 2011 and 2010 were as follows (in thousands):

	2011		2010	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 5,562,925**	**$ 6,781,065**	$ 4,657,127	$ 5,139,336

The fair value of long-term debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to us for debt of similar maturities. Our three primary sources of long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank. We also have small amounts of long term debt provided by CFC and by CoBank. The valuations for the first mortgage bonds and the pollution control revenue bonds are provided by a third-party investment banking firm. These valuations are based on market prices for similar debt in active markets. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of December 31, 2011 (plus a spread of ⅛ percent). The additional spread of ⅛ percent is reflective of the "cost" the Rural Utilities Service attributes to making these loans. We use an interest rate quote sheet provided by CoBank for valuation of the CoBank debt. The quotes contained in CoBank's rate sheet are adjusted for our "A" credit rating. The rates on the CFC debt are fixed and the valuation is based on rate quotes provided by CFC.

We use the methods and assumptions described above to estimate the fair value of each class of financial instruments. For cash and cash equivalents, restricted cash and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments.

Derivative instruments

Our risk management and compliance committee provides general oversight over all risk management activities, including but not limited to, commodity trading, investment portfolio management and interest rate risk management. We use commodity trading derivatives, which are designated as hedging instruments under authoritative guidance for accounting for derivatives and hedging, to manage our exposure to fluctuations in the market price of natural gas. Consistent with our rate-making treatment for energy costs which are flowed-through to our members, unrealized gains or losses on natural gas swaps are reflected as an unbilled receivable. To hedge the risk of rising interest rates due to the significant amount of new long-term debt we will incur in connection with anticipated capital expenditures, we have entered into interest rate options. Hedge accounting is not applied to our interest rate options. Consistent with our rate-making treatment, unrealized gains or losses from the interest rate options are recorded to the related regulatory asset. Within our nuclear decommissioning trust fund, derivatives including options, swaps and credit default swaps which are non-speculative, are utilized to mitigate volatility associated with duration, default, yield curve and the interest rate risks of the portfolio. We do not hold or enter into derivative transactions for trading or speculative purposes. Consistent with our rate-making treatment, unrealized gains or losses from the decommissioning trust fund are recorded as an increase or decrease to the regulatory asset or liability.

We are exposed to credit risk as a result of entering into these hedging arrangements. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement, and exposure monitoring and mitigation.

It is possible that volatility in commodity prices and/or interest rates could cause us to have credit risk exposures with one or more natural gas counterparties and we currently have credit risk exposure to our interest rate options counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of December 31, 2011, all of the counterparties with transaction amounts outstanding under our hedging programs are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

We have entered into International Swaps and Derivatives Association agreements with our natural gas hedge and interest rate option counterparties that mitigate credit exposure by creating contractual rights relating to creditworthiness, collateral, termination and netting (which allows us to use the net value of affected transactions with the same counterparty in the event of default by the counterparty or early termination of the agreement).

Additionally, we have implemented procedures to monitor the creditworthiness of our counterparties and to evaluate nonperformance in valuing counterparty positions. We have contracted with a third party to assist in monitoring certain of our counterparties' credit standing and condition. Net liability positions are generally not adjusted as we use derivative transactions as hedges and have the ability and intent to perform under each of our contracts. In the instance of net asset positions, we consider general market conditions and the observable financial health and outlook of specific counterparties, forward looking data such as credit default swaps, when available, and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

The contractual agreements contain provisions that could require us or the counterparty to post collateral or credit support. The amount of collateral or credit support that could be required is calculated as the difference between the aggregate fair value of the hedges and pre-established credit thresholds. The credit thresholds are contingent upon each party's credit standing and credit ratings from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty.

Gas hedges. Under the natural gas swap arrangements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment.

At December 31, 2011 and December 31, 2010 the estimated fair value of our natural gas contracts was an unrealized loss of approximately $7,220,000 and $2,054,000, respectively.

As of December 31, 2011, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011 due to our credit rating being downgraded below investment grade, we could have been required to post letters of credit totaling up to $7,220,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of December 31, 2011 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBtu) (in millions)
2012	6.23
2013	0.83
Total	**7.06**

Interest rate options. We are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we will incur in connection with anticipated capital expenditures, particularly the construction of Plant Vogtle Units No. 3 and No. 4. We have entered into a conditional term sheet with the Department of Energy to finance up to $3.057 billion of the cost to construct Plant Vogtle Units No. 3 and No.4. The term sheet provides for quarterly draws from 2012 through 2017 and interest rates that will be based on U.S. Treasury rates at the time of each draw, plus a fixed spread. In fourth quarter of 2011, we completed the purchase of $100,000,000 in interest rate options to hedge the interest rates on approximately $2.2 billion of the Department of Energy-guaranteed loan, representing a substantial portion of the expected borrowings from 2013 through 2017.

The interest rate options, commonly known as LIBOR swaptions, give us the right, but not the obligation, to enter into a swap in which we would pay a fixed rate and receive a floating LIBOR rate. However, the swaptions are required to be cash settled based on their value on the expiration date, thereby effectively capping our interest rates by offsetting the present value cost of an increase in interest rates above the fixed rate. The cash settlement value depends on the extent to which prevailing LIBOR swap rates exceed the fixed rate on the underlying swap, and the value would be zero if swap rates are at or below the fixed rate upon expiration. The fixed rates on the LIBOR swaptions we purchased are in the range of 100 to 200 basis points above current LIBOR swap rates and the weighted average fixed rate is 4.17%. The swaptions' expiration dates, which range from 2013 through 2017, are timed to match the expected quarterly draw dates of the Department of Energy-guaranteed loan advances to be hedged. As the interest rate options' value is independent from the Department of Energy-guaranteed loan, the interest rate options could also serve as a hedge of interest rates on an alternative source of financing.

We paid the entire premiums at the time we entered into these interest rate option transactions and have no additional payment obligations. However, upon expiration of the interest rate options, each counterparty will be obligated to pay us the cash value of the interest rate options, if any. To manage our credit exposure to these counterparties, we negotiated credit support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the interest rate options outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from $0 to $10,000,000 depending on each counterparty's credit rating. As of December 31, 2011, we held $43,070,000 of funds posted as collateral by the counterparties. The collateral received is recorded as long-term restricted cash on our balance sheets. The liability associated with the collateral is recorded as an offset to the fair values of the interest rate options.

These derivatives are recorded at fair value and hedge accounting is not applied. At December 31, 2011, the fair value of these interest rate options was approximately $69,446,000. We are deferring gains or losses from the change in fair value of each interest rate option and related carrying and other incidental costs in accordance with our approved rate-making for these costs. The deferred costs, which are not expected to exceed $135,000,000, and deferred gains, if any, from the settlement of the interest rate options will be amortized and collected in rates over the life of the expected Department of Energy-guaranteed loan or alternative financing.

We estimate the value of the LIBOR swaptions utilizing an option pricing model based on several inputs including the notional amount, the forward LIBOR swap rates, the option volatility, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, as well as credit attributes, including the credit spread of the counterparty and the amount of credit support that is available for each swaption. The fair value of the swaptions is sensitive to certain of these inputs, especially option volatility. We are able to effectively observe all of these factors using a variety of market sources except for the credit spreads of certain counterparties and the option volatility. We are able to estimate option volatility implied by valuations we obtain from various sources, but the valuations, and therefore the implied option volatilities vary considerably from one source to another. Since valuations of comparable instruments are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We considered both any intrinsic value and the remaining time value associated with the derivatives and considered counterparty credit risk in our determination of all estimated fair values. We believe the estimated fair values for the LIBOR swaptions we hold are based on the most accurate information available for these types of derivative contracts.

The following table reflects the notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of December 31, 2011:

Year	**LIBOR Swaption Notional Dollar Amount** (in thousands)
2012	$ –
2013	754,452
2014	563,425
2015	470,625
2016	310,533
2017	80,169
Total	**$ 2,179,204**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets for the period ending December 31, 2011 and December 31, 2010.

	Balance Sheet Location	**Fair Value**	
		2011	**2010**
		(dollars in thousands)	
Designated as hedges under authoritative guidance related to derivatives and hedging activities:			
Assets			
Natural gas swaps	Receivables	**$ 7,220**	$ 2,054
Total assets designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 7,220**	$ 2,054
Liabilities			
Natural gas swaps	Other current liabilities	**$ 7,220**	$ 2,629
Natural gas swaps	Other current liabilities	**–**	(575)
Total liabilities designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 7,220**	$ 2,054
Not designated as hedges under authoritative guidance related to derivatives and hedging activities:			
Assets			
Nuclear decommissioning trust	Nuclear Decommissioning trust fund	**$ 792**	$ 290
Nuclear decommissioning trust	Nuclear Decommissioning trust fund	**(1,774)**	(742)
Nuclear decommissioning trust	Regulatory assets	**1,447**	359
Nuclear decommissioning trust	Regulatory assets	**(929)**	(231)
Interest rate options	Other long-term assets	**69,446**	–
Interest rate options	Regulatory assets	**30,554**	–
Total not designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 99,537**	$ (324)

The following table presents the gains and (losses) on derivative instruments recognized in margin or deferred on the balance sheet for the year ended December 31, 2011 and December 31, 2010.

Effect of Derivative Instruments on the Consolidated Statement of Revenues and Expenses or Balance Sheet

	Consolidated Statement of Revenues and Expenses or Balance Sheet Location	2011	2010	2009
		(dollars in thousands)		
Designated as hedges under authoritative guidance related to derivatives and hedging activities				
Natural Gas Swaps	Purchased power	**$ 195**	$ –	$ 46
Natural Gas Swaps	Purchased power	**(4,151)**	(19,734)	(30,635)
Not designated as hedges under authoritative guidance related to derivatives and hedging activities				
Nuclear decommissioning trust	Regulatory asset	**3,602**	2,689	3,477
Nuclear decommissioning trust	Regulatory asset	**(2,557)**	(2,564)	(3,702)
Total losses on derivatives		**$ (2,911)**	$ (19,609)	$ (30,814)

Investments in debt and equity securities

Under the accounting guidance for Investments — Debt and Equity Securities, investment securities we hold are classified as available-for-sale. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from patronage capital, except that, in accordance with our rate-making treatment, unrealized gains and losses from investment securities held in the nuclear decommissioning trust fund are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 58% of these gross unrealized losses were in effect for less than one year.

For those securities considered to be available-for-sale, the following table summarizes the activities for those securities as of December 31, 2011 and 2010:

	(dollars in thousands)			
		Gross Unrealized		
2011	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 149,263**	**$ 29,789**	**$ (9,996)**	**$ 169,056**
Debt	**160,218**	**18,021**	**(11,063)**	**167,176**
Other	**15,646**	**1,035**	**(1,541)**	**15,140**
Total	**$ 325,127**	**$ 48,845**	**$ (22,600)**	**$ 351,372**
		Gross Unrealized		
2010	Cost	Gains	Losses	Fair Value
Equity	$ 137,492	$ 42,622	$ (2,482)	$ 177,632
Debt	158,706	9,130	(4,879)	162,957
Other	7,035	3	(118)	6,920
Total	$ 303,233	$ 51,755	$ (7,479)	$ 347,509

All of the available-for-sale investments are marked to market in the accompanying consolidated balance sheets, therefore the carrying value equals the fair value.

The contractual maturities of debt securities available-for-sale, which are included in the estimated fair value table above, at December 31, 2011 and 2010 are as follows:

	(dollars in thousands)			
	2011		2010	
	Cost	**Fair Value**	Cost	Fair Value
Due within one year	**$ 2,074**	**$ 2,051**	$ 24,887	$ 24,862
Due after one year through five years	**32,149**	**32,598**	32,182	32,979
Due after five years through ten years	**68,987**	**74,010**	59,336	62,375
Due after ten years	**57,008**	**58,517**	42,301	42,741
Total	**$ 160,218**	**$ 167,176**	$ 158,706	$ 162,957

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2011, 2010 and 2009:

	(dollars in thousands) For the years ended December 31,		
	2011	2010	2009
Gross realized gains	**$ 31,130**	$ 24,634	$ 17,537
Gross realized losses	**(16,215)**	(10,395)	(24,475)
Proceeds from sales	**1,064,377**	622,124	633,707

Investment in associated companies,

Investments in associated companies were as follows at December 31, 2011 and 2010:

	(dollars in thousands)	
	2011	2010
National Rural Utilities Cooperative Finance Corporation (CFC)	**$ 23,993**	$ 23,979
CoBank, ACB	**3,345**	3,433
CT Parts, LLC	**5,633**	5,640
Georgia Transmission Corporation	**19,291**	17,634
Georgia System Operations Corporation	**3,911**	4,009
Other	**1,453**	1,430
Total	**$ 57,626**	$ 56,125

The National Rural Utilities Cooperative Finance Corporation (CFC) investments are primarily in the form of capital term certificates and are required in conjunction with our membership in CFC. Accordingly, there is no market for these investments. The investments in CoBank and Georgia Transmission represent capital credits. Any distributions of capital credits are subject to the discretion of the board of directors of CoBank and Georgia Transmission. The investments in Georgia System Operations represent loan advances. The loan repayment schedule ends in December 2015.

CT Parts, LLC is an affiliated organization formed by Oglethorpe and Smarr EMC for the purpose of purchasing and maintaining a spare parts inventory and administration of contracted services for combustion turbine generation facilities. Such investment is recorded at cost.

We and our 39 members are members of Georgia Transmission. Georgia Transmission provides transmission services to its members for delivery of its members' power purchases from us and other power suppliers. We have entered into an agreement with Georgia Transmission to provide transmission services for third party transactions and for service to our own facilities. For 2011, 2010, and 2009, we incurred expenses from Georgia Transmission of $25,128,000, $25,491,000, and $23,678,000, respectively.

We, Georgia Transmission and 38 of our members are members of Georgia Systems Operations. Georgia Systems Operations operates the system control center and currently provides us system operations services and administrative support services. For 2011, 2010, and 2009, we incurred expenses from Georgia Systems Operations of $17,793,000, $16,848,000, and $17,467,000, respectively.

Smarr EMC is a Georgia electric membership corporation owned by 36 of our 39 members. Smarr EMC owns two combustion turbine facilities. We provide operations, financial and management services for Smarr EMC.

Rocky Mountain transactions

In December 1996 and January 1997, we entered into six long-term lease transactions relating to our 74.61% undivided interest in the Rocky Mountain pumped storage hydro facility, through our wholly owned subsidiary, RMLC. RMLC leases from six owner trusts the undivided interest in Rocky Mountain and subleases it back to us. The Deposit on Rocky Mountain transactions, which is carried at cost, was made in connection with these lease transactions and is invested in guaranteed investment contracts which will be held to maturity (the end of the 30-year lease-back period). At the end of the base lease term, we have the option, through RMLC, to purchase any owner trust's undivided interest in Rocky Mountain. If we elect to exercise the purchase option, the funds in the guaranteed investment contracts will be used to pay a portion ($371,850,000) of the fixed purchase price.

In addition to the funding of the guaranteed investment contracts, the proceeds also funded the Payment Undertaking Agreements with Rabobank Nederland. RMLC paid $640,611,000 to fund these Payment Undertaking Agreements with Rabobank whose senior debt obligations are rated AA by S&P and Aaa by Moody's. In return, Rabobank undertook to pay all of RMLC's periodic basic rent payments under the Facility Subleases and to pay the remaining portion of the fixed purchase price ($714,923,000) should we, through RMLC, elect to purchase the facility at the end of the base lease term. RMLC's corresponding lease obligations have been extinguished for financial reporting purposes. RMLC remains liable for all payments of basic rent under the Facility Leases if the Payment Undertaker fails to make such payments, although the owner trusts have agreed to use due diligence to pursue the Payment Undertaker before pursuing payment from us or RMLC. In 2011, RMLC would have been required to make basic rent payments totaling $58,033,000 to the owner trusts if the Payment Undertaker had failed to make such payments. The fair value amount relating to the guarantee of basic rent payments is immaterial principally due to the high credit rating of the Payment Undertaker.

The operative agreements relating to the Rocky Mountain lease transactions require us to maintain surety bonds with a surety bond provider that meets minimum credit rating requirements to secure certain of our payment obligations under the Rocky Mountain lease transactions. The operative agreements relating to the Rocky Mountain lease transactions provide that the surety bond provider must maintain a credit rating of at least AA from S&P or Aa2 from Moody's, and if such rating is not maintained, then we must, within 60 days of becoming aware of such fact, provide (i) a replacement surety bond from a surety bond provider that has such credit ratings, (ii) a letter of credit from a bank with such credit ratings, (iii) other acceptable credit enhancement or (iv) any combination thereof.

In November 2008, the surety bond provider's (AMBAC) credit ratings fell below the minimum threshold, triggering the requirement for us to provide the replacement credit enhancement discussed above. In two separate transactions that closed in May 2009 (relating to five of the leases) and in August 2009 (relating to the sixth lease), we entered into agreements with Berkshire Hathaway Assurance Corporation pursuant to which they are providing us with supplemental credit enhancement to the credit enhancement provided by AMBAC, thereby satisfying our obligation to provide replacement credit enhancement.

Berkshire is currently rated AA+ by S&P and Aa1 by Moody's. If Berkshire is downgraded below AA by S&P and Aa2 by Moody's, we will be obligated to replace, within 60 days of becoming aware of that fact, the Berkshire surety bonds for all six of the lease transactions, with other qualified credit enhancement.

The assets of RMLC are not available to pay our creditors or our affiliates' creditors.

3. Income taxes:

We are a not-for-profit membership corporation subject to federal and state income taxes. As a taxable electric cooperative, we have annually allocated income and deductions between patronage and non-patronage activities.

Although we believe that treatment of non-member sales as patronage-sourced income is appropriate, this treatment has not been examined by the Internal Revenue Service. If this treatment was not sustained, we believe that the amount of taxes on such non-member sales, after allocating related expenses against the revenues from such sales, would not have a material adverse effect on financial condition or results of operations and cash flows.

We account for income taxes pursuant to the authoritative guidance for accounting for income taxes, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns.

The difference between the statutory federal income tax rate on income before income taxes and our effective income tax rate is summarized as follows:

	2011	2010	2009
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Patronage exclusion	**(32.6%)**	(32.9%)	(31.4%)
Tax credits	**0.0%**	(0.0%)	(0.1%)
Other	**(2.4%)**	(2.1%)	(3.6%)
Effective income tax rate	**(0.0%)**	(0.0%)	(0.1%)

The components of the net deferred tax assets as of December 31, 2011 and 2010 were as follows:

	(dollars in thousands)	
	2011	2010
Deferred tax assets		
Net operating losses	**$ 29,724**	$ 29,724
Tax credits (alternative minimum tax and other)	**1,535**	1,633
	31,259	31,357
Less: Valuation allowance	**(31,259)**	(31,357)
Net deferred tax assets	**$ –**	$ –
Deferred tax liabilities		
Depreciation	**$ –**	$ –
	–	–
Net deferred tax liabilities	**$ –**	$ –

As of December 31, 2011, we have federal tax net operating loss carryforwards and alternative minimum tax credits as follows:

	(dollars in thousands)		
Expiration Date	Minimum Alternative Tax Credits	Tax Credits	NOLs
2018	$ –	$ –	$ 61,533
2019	–	–	10,516
2020	–	–	4,362
None	1,633	–	–
	$ 1,633	$ –	$ 76,411

The net operating loss expiration dates start in the year 2018 and end in the year 2020. Due to the tax basis method for allocating patronage and as shown by the above valuation allowance, it is not likely that the deferred tax assets related to tax credits and net operating losses will be realized. The change in the valuation allowance from 2010 to 2011 was the result of the reduction in deferred tax assets due to the utilization and expiration of tax credits, net operating losses and the implementation of authoritative guidance.

The authoritative guidance for income taxes addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. We may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement.

We file a U.S. federal consolidated income tax return. The U.S. federal statute of limitations remains open for the year 2008 forward. State jurisdictions have statutes of limitations generally ranging from three to five years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by tax authorities in major state jurisdictions include 2008 forward.

As a result of the adoption in 2006 of the authoritative guidance for uncertain tax positions, we recognized a $96,000,000 increase in the liability for unrecognized tax benefits. This change in the liability resulted in no decrease to the January 1, 2009 balance of patronage capital as the effects were offset by recognition of deferred tax assets. During each of the third quarters of 2009 and 2010, the two remaining open years expired. Accordingly, this liability and related deferred tax asset was reduced by $24,000,000 during each third quarter. At the end of the third quarter of 2010, the last open year related to uncertain tax position expired.

The unrecognized tax benefit reconciliation from beginning balance to ending balance is as follows for the years 2011, 2010, and 2009:

	(dollars in thousands)
Unrecognized tax benefits at year end (December 31, 2009)	$ 24,000
Reduction of tax positions as a result of statue of limitation expiration	(24,000)
Unrecognized tax benefits at year end (December 31, 2010)	$ –
Reduction of tax positions as a result of statue of limitation expiration	–
Unrecognized tax benefits at year end (December 31, 2011)	**$ –**

4. Capital leases:

In 1985, we sold and subsequently leased back from four purchasers their 60% undivided ownership interest in Scherer Unit No. 2. The gain from the sale is being amortized over a 36-year term, which includes the basic term and a guaranteed minimum extension term (of no less than 8.5 years) provided for in the leases. The renewal provisions provide that we may extend the leases for a period beyond the basic term by giving irrevocable notice of renewal by June 2012, subject to fulfilling certain contractual requirements included in the leases. The lease extension would begin June 2013.

In 2000, we entered into a power purchase and sale agreement with Doyle I, LLC (Doyle Agreement) to purchase all of the output from a five-unit generation facility (Doyle) for a period of 15 years.

The minimum lease payments under the capital leases together with the present value of the net minimum lease payments as of December 31, 2011 are as follows:

Year Ending December 31,	(dollars in thousands)		
	Scherer Unit No. 2	Doyle	Total
2012	$ 46,255	$ 12,447	$ 58,702
2013	24,093	12,447	36,540
2014	16,326	12,447	28,773
2015	16,326	18,297	34,623
2016	16,326	–	16,326
2017-2021	81,632	–	81,632
Total minimum lease payments	200,958	55,638	256,596
Less: Amount representing interest	(57,963)	(6,733)	(64,696)
Present value of net minimum lease payments	142,995	48,905	191,900
Less: Current portion	(35,341)	(9,778)	(45,119)
Long-term balance	$ 107,654	$ 39,127	$ 146,781

For Doyle, the lease payments vary to the extent the interest rate on the lessor's debt varies from 6.00%. At December 31, 2011, the weighted average interest rate on the Doyle lease obligation was 5.86% as compared to 6.06% at December 31, 2010.

The Scherer No. 2 lease and the Doyle Agreement are reported as capital leases. For rate-making purposes, however, we include the actual lease payments in our cost of service. The difference between lease payments and the aggregate of the amortization on the capital lease asset and the interest on the capital lease obligation is recognized as a regulatory asset on the balance sheet. Capital lease amortization is recorded in depreciation and amortization expense.

5. Debt:

Long-term debt consists of first mortgage notes payable to the United States of America acting through the Federal Financing Bank and the Rural Utilities Service, first mortgage bonds payable, first mortgage notes issued in conjunction with the sale by public authorities of pollution control bonds, first mortgage notes payable to CoBank and CFC and unsecured notes payable to three commercial banks. Substantially all of our owned tangible and certain of our intangible assets are pledged under our first mortgage indenture as collateral for the Federal Financing Bank and Rural Utilities Service notes, the first mortgage bonds, the first mortgage notes issued in conjunction with the sale of pollution control bonds, and the CoBank and CFC first mortgage notes.

In March 2011, the Development Authority of Appling County (Georgia), the Development Authority of Burke County (Georgia) and the Development Authority of Monroe County (Georgia) issued, on our behalf, $180,380,000 in aggregate principal amount of tax-exempt pollution control revenue bonds for the purpose of refunding certain pollution control revenue bonds previously issued by the development authorities on our behalf. The Series 2011 bonds are term rate bonds with a 2.5% interest rate which is fixed through February 28, 2013. $168,700,000 of the 2011 bonds proceeds were used to refund a like amount of Series 2007 and 2008 pollution control revenue bonds that were subject to remarketing and interest rate reset on April 1, 2011. In conjunction with this refunding, we provided notice of optional redemption of the prior bonds in March 2011 and redeemed the bonds on April 1, 2011. The remaining proceeds of the 2011 bond issue were used to refund $11,680,000 of commercial paper that was used to refund a like amount of pollution control revenue bonds that matured on January 1, 2011.

On April 6, 2011, we closed a $260,000,000 three-year term loan with three banks to provide a portion of the interim financing for the Murray acquisition on April 8, 2011. The current interest rate on the loan is 1.53% and is based on one-month LIBOR. The term loan is set to mature in April 2014. For a discussion of the Murray acquisition, see Note 12.

On August 19, 2011, we issued $300,000,000 of 5.25% First Mortgage Bonds, Series 2011 A primarily for the purpose of repaying outstanding commercial paper issued in connection with funding a portion of the cost of constructing Vogtle Units No. 3 and No. 4. The first mortgage bonds are secured under our first mortgage indenture.

During 2011, we received advances on Rural Utilities Service guaranteed Federal Financing Bank loans totaling $423,813,000 to permanently finance the 2009 Hartwell and Hawk Road acquisitions and for environmental and general improvements at existing plants.

The annual interest requirement on our long-term debt for 2012 is estimated to be $314,649,000.

Maturities for long-term debt and capital lease obligations through 2016 are as follows:

	(dollars in thousands) 2012	2013	2014	2015	2016
FFB	$ 115,098	$ 100,125	$ 104,366	$ 108,892	$ 113,232
CFC	729	767	806	848	891
CoBank	490	551	621	698	786
PCBs	10,371(1)	74,703(2)	37,352(2)	133,550(2)	–
CREBs	1,010	1,010	1,010	1,010	1,010
Term Loans	–	–	260,000	–	–
	127,698	177,156	404,155	244,998	115,919
Capital Leases	45,120	25,726	18,705	26,279	9,527
Total	$ 172,818	$ 202,882	$ 422,860	$ 271,277	$ 125,446

(1) Reflects only our 83.14% share of the pollution control bond maturity and does not include the portion assumed by Georgia Transmission. The 2012 PCB maturity was refinanced on an interim basis with commercial paper in January 2012, and a plan is in place to refinance this with long-term pollution control bond debt in April 2012.

(2) These are not regularly scheduled principal payments but instead represent amounts that would be due if the credit support facilities for the 2009 and 2010 pollution control bonds were drawn upon and became payable in accordance with their terms. To date, none of these credit support facilities have been drawn upon for principal and we anticipate extending these facilities before their expiration. The nominal maturities of the 2009 and 2010 pollution control bonds range from 2030 through 2038.

The weighted average interest rate for long-term debt and capital leases was 4.85% at December 31, 2011 as compared to 5.23% at December 31, 2010.

We have $1,925,000,000 of committed credit arrangements comprised of five separate facilities with maturity dates that range from November 2012 to September 2016. These short-term credit facilities are for general working capital purposes and to provide temporary funding for our construction and acquisition financings. Along with the lines of credit from CFC, JPMorgan Chase Bank and CoBank, funds may be advanced under the syndicated line of credit for general working capital purposes. Under certain of our committed lines of credit we have the ability to issue letters of credit totaling $910,000,000 in the aggregate. At December 31, 2011, we had (1) $253,000,000 under these lines of credit in the form of letters of credit supporting variable rate pollution control revenue bonds and to post collateral to third parties and (2) $461,199,000 under one of these lines of credit was utilized as support for a like amount of commercial paper we issued that is outstanding.

6. Electric plant, construction and related agreements:

a. Electric plant

We, along with Georgia Power, have entered into agreements providing for the purchase and subsequent joint operation of certain of Georgia Power's and our electric generating plants. The plant investments disclosed in the table below represent our undivided interest in each co-owned plant, and each co-owner is responsible for providing its own financing. A summary of our plant investments and related accumulated depreciation as of December 31, 2011 is as follows:

Plant	**2011** Investment	**2011** Accumulated Depreciation	2010 Investment	2010 Accumulated Depreciation
	(dollars in thousands)			
In-service				
Owned property				
Vogtle Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**$ 2,726,129**	**$ (1,528,841)**	$ 2,722,168	$ (1,497,484)
Hatch Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**603,865**	**(369,189)**	594,712	(356,088)
Wansley Units No. 1 & No. 2 *(Fossil – 30% ownership)*	**394,596**	**(129,994)**	392,217	(122,452)
Scherer Unit No. 1 *(Fossil – 60% ownership)*	**663,583**	**(269,525)**	598,674	(264,375)
Rocky Mountain Units No. 1, No. 2 & No. 3 *(Hydro – 75% ownership)*	**584,569**	**(176,356)**	575,266	(167,711)
Hartwell (Combustion Turbine – *100% ownership)*	**223,936**	**(85,337)**	223,766	(80,865)
Hawk Road (Combustion Turbine – *100% ownership)*	**241,587**	**(51,253)**	238,719	(45,991)
Talbot (Combustion Turbine – *100% ownership)*	**280,413**	**(77,616)**	279,928	(69,244)
Chattahoochee (Combined cycle – *100% ownership)*	**299,117**	**(79,285)**	299,117	(70,314)
Murray (Combined cycle – *100% ownership)*	**554,158**	**(109,741)**	–	–
Wansley (Combustion Turbine – *30% ownership)*	**3,684**	**(3,084)**	3,676	(2,946)
Transmission plant	**78,470**	**(41,539)**	71,919	(40,213)
Other	**106,083**	**(64,433)**	101,569	(61,388)
Property under capital lease:				
Doyle (Combustion Turbine – *100% leasehold)*	**126,990**	**(80,030)**	126,990	(77,514)
Scherer Unit No. 2 (Fossil – *60% leasehold)*	**448,686**	**(262,362)**	443,532	(245,146)
Total in-service	**$ 7,335,866**	**$ (3,328,585)**	$ 6,672,253	$ (3,101,731)
Construction work in progress				
Generation improvements	**$ 1,783,246**		$ 1,180,347	
Other	**1,018**		15,128	
Total construction work in progress	**$ 1,784,264**		$ 1,195,475	

Our proportionate share of direct expenses of joint operation of the above plants is included in the corresponding operating expense captions (e.g., fuel, production or depreciation) on the accompanying statements of revenues and expenses.

b. Construction

In April 2008, Georgia Power, acting for itself and as agent for Oglethorpe, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia (collectively, Owners), and a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement (Vogtle No. 3 and No. 4 Agreement) to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle Units No. 3 and No. 4).

The Vogtle No. 3 and No. 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 No. 3 and No. 4 Agreement, the Owners will 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 No. 3 and No. 4 Agreement. Our proportionate share is 30.0%.

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.

The NRC certified Westinghouse's Design Certification Document (DCD) as amended 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 the issuance of combined operating permits and construction licenses (COLs). The COLs were received on February 10, 2012. Receipt of the COLs allows full construction to begin on Vogtle Units No. 3 and No. 4, which are scheduled to be placed in service in 2016 and 2017, respectively.

There are pending technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 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.

We estimate our proportionate share of the costs to construct Plant Vogtle Units No. 3 and No. 4 will be $4,200,000,000. At December 31, 2011, our total capitalized costs to date were approximately $1,287,649,000.

7. Employee benefit plans:

Our retirement plan is a contributory 401(k) that covers substantially all employees. An employee may contribute, subject to IRS limitations, up to 60% of his or her eligible annual compensation. At our discretion, we may match the employee's contribution and have done so each year of the plan's existence. Our current policy is to match the employee's contribution as long as there is sufficient margin to do so. The match, which is calculated each pay period, currently can be equal to as much as three-quarters of the first 6% of an employee's eligible compensation, depending on the amount and timing of the employee's contribution. Our contributions to the matching feature of the plan were approximately $925,000 in 2011, $867,000 in 2010 and $759,000 in 2009. Our contribution to the employer retirement contribution feature was 8%. Our contributions to the employer retirement contribution feature of the 401(k) plan were approximately $1,844,000 in 2011, $1,712,000 in 2010 and $1,460,000 in 2009.

8. Nuclear insurance:

The Price-Anderson Act, limits public liability claims that could arise from a single nuclear incident to $12.6 billion. This amount is covered by private insurance and a mandatory program of deferred premiums that could be assessed against all owners of nuclear power reactors. Such private insurance provided by American Nuclear Insurers ("ANI") (in the amount of $375,000,000 for each plant, the maximum amount currently available) is carried by Georgia Power for the benefit of all the co-owners of Plants Hatch and Vogtle. Agreements of indemnity have been entered into by and between each of the co-owners and the Nuclear Regulatory Commission. In the event of a nuclear incident involving any commercial nuclear facility in the country involving total public liability in excess of $375,000,000, a licensee of a nuclear power plant could be assessed a deferred premium of up to $117,500,000 per incident for each licensed reactor operated by it, but not more than $17,500,000 per reactor per incident to be paid in a calendar year. On the basis of our ownership interest in four nuclear reactors, we could be assessed a maximum of $141,000,000 per incident, but not more than $21,000,000 in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years, and exclude any applicable state premium taxes. The next scheduled adjustment is due no later than October 29, 2013.

Georgia Power, on behalf of all the co-owners of Plants Hatch and Vogtle, is a member of Nuclear Electric Insurance, Ltd. (''NEIL''), a mutual insurer established to provide property damage insurance coverage in an amount up to $500,000,000 for members' operating nuclear generating facilities. Additionally, Georgia Power provides coverage through NEIL for decontamination, premature decommissioning and excess property damage to nuclear generating facilities for an additional $2,250,000,000 for losses in excess of the $500,000,000 primary coverage described above.

Georgia Power, on behalf of all the co-owners has purchased a builders' risk property insurance policy from NEIL for Plant Vogtle Units No. 3 and No.4. This policy provides $2,750,000,000 in limits for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to retroactive assessments in proportion to their premiums, if losses each year exceed the accumulated reserve funds available to the insurer under that policy. The portion of the current maximum annual assessment for Georgia Power that would be payable by us based on ownership share, is limited to approximately $31,100,000.

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 $3,200,000,000 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 Nuclear Regulatory Commission 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 next to be applied toward the costs of decontamination and debris removal operations ordered by the Nuclear Regulatory Commission, and any further remaining proceeds are to be paid either to the company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability or property, may be subject to applicable state premium taxes. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses. Uninsured losses and other expenses could have a material adverse effect on our financial condition and results of operations.

9. Commitments:

a. Operating leases

As of December 31, 2011, our estimated minimum rental commitments for our railcar leases for use at our coal-fired facilities over the next five years and thereafter are as follows:

Year Ending December 31,	(dollars in thousands)
2012	$ 5,764
2013	5,764
2014	5,764
2015	4,432
2016	4,432
Thereafter	11,511

The rental expenses for the railcar leases are added to the cost of the fossil inventories and are recognized in fuel expense. Rental expenses totaled $5,190,000 in 2011, $5,265,000 in 2010 and $5,230,000 in 2009.

b. Fuel

To supply a portion of the fuel requirements to our generating units, Southern Nuclear on our behalf for nuclear fuel, and Georgia Power, on our behalf for coal, have entered into various long-term commitments for the procurement of coal and nuclear fuel. The contracts in most cases contain provision for price escalations, minimum purchase levels and other financial commitments. The value of the coal commitments is based on maximum coal prices and minimum volumes as provided in the contracts and does not include taxes, transportation or government impositions. For further discussion of total nuclear fuel expense, see Note 1h.

As of December 31, 2011, our estimated minimum long-term commitments are as follows:

Year Ending December 31,	(dollars in thousands)	
	Coal	Nuclear Fuel
2012	$ 89,353	$ 77,100
2013	77,605	50,100
2014	40,369	48,900
2015	–	30,600
2016	–	21,300
Thereafter	–	158,400

10. Guarantees:

As of December 31, 2011 and 2010, our guarantees included those disclosed in Note 5 for pollution control bonds assumed by Georgia Transmission in connection with a corporate restructuring and for rental payments due under the terms of the Rocky Mountain lease transactions and replacement credit enhancement. See Note 2 for discussion of Rocky Mountain lease transactions.

In connection with our corporate restructuring in 1997, Georgia Transmission assumed 16.86% of the then outstanding indebtedness associated with pollution control bonds pursuant to an assumption agreement and an indemnity agreement. If Georgia Transmission fails to satisfy its obligation under this debt assumption, we remain liable for any unsatisfied amounts. In that event, we would be entitled to reimbursement from Georgia Transmission for any amounts we paid. At December 31, 2011, the total obligation assumed by Georgia Transmission related to outstanding pollution control bonds was $40,105,000.

The amount of the fair value of our guarantee related to the pollution control bonds assumed by Georgia Transmission is immaterial due to the small amount of assumed principal outstanding and the high credit rating of Georgia Transmission. We estimate that the current maximum aggregate amount of exposure we would have if we were required to purchase the equity interests of the six owner trusts under the Rocky Mountain lease transactions is approximately $250,000,000. See Note 2 for discussion of Rocky Mountain lease transactions.

11. Environmental matters:

As is typical for electric utilities, we are subject to various federal, state and local air and water quality requirements which, among other things, regulate emissions of pollutants, such as particulate matter, sulfur dioxide, nitrogen oxides and mercury into the air and discharges of other pollutants, including heat, into waters of the United States, which represent significant future risks and uncertainties. In 2011, we became subject to climate change regulations that impose restrictions on emissions of greenhouse gases, including carbon dioxide, through the Prevention of Significant Deterioration preconstruction permitting program. As a result, we are required to evaluate any new generation projects as well as any major modifications that we plan to undertake at our existing plants to determine whether they will need to undergo new source review permitting for greenhouse gases (in addition to the other pollutants for which new source review was already required), and, if they do, whether any control technology will need to be added. We are also subject to federal, state and local waste disposal requirements that regulate the manner of transportation, storage and disposal of various types of waste.

In general, environmental requirements are becoming increasingly stringent. Any new requirements in the future but not in existence now may substantially increase the cost of electric service by requiring changes in the design or operation of existing facilities or changes or delays in the location, design, construction or operation of new facilities. Failure to comply with any new requirements could result in the imposition of civil and criminal penalties as well as the complete shutdown of individual generating units not in compliance. Certain of our debt instruments and credit agreements require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current or future environmental laws and regulations. We believe that we are in compliance with those environmental regulations currently applicable to our business and operations. Should we fail to be in compliance with these requirements, or any new requirements, it would constitute a default under such debt instruments and credit agreements. Although it is our intent to comply with applicable current and future regulations, we cannot provide assurance that we will always be in compliance with such requirements.

At this time, the ultimate impact of any new and more stringent environmental regulations described above is uncertain and could have an effect on our financial condition, results of operations and cash flows as a result of future additional capital expenditures and increased operations and maintenance costs.

We are currently not subject to any environmental or other loss contingencies for which we believe it is probable or reasonably possible that a loss has been incurred that would be material to our financial position, results of operations or cash flows.

12. Plant acquisitions:

a. Murray Energy Facility

On April 8, 2011, we acquired 100% of KGen Murray I and II LLC, a wholly owned subsidiary of KGen Power Corporation. KGen Murray I and II LLC, subsequently renamed Murray I and II, LLC, owns the Murray Energy Facility, located near Dalton, Georgia. This facility consists of two natural gas-fired combined cycle units that have an aggregate summer planning reserve generation capacity of approximately 1,250 megawatts. In connection with this acquisition, we cancelled our previously announced plans to construct our own combined cycle plant.

As part of the acquisition, we assumed an existing power purchase and sale agreement with Georgia Power for the entire output of Murray Unit No. 1 through May 31, 2012. Our members generally plan to take the output of Murray beginning in 2016 in connection with their forecasted power requirements. Prior to our members' use of Murray, energy may be sold into the wholesale market in order to reduce the net cost of this facility to our members.

We accounted for the transaction as a purchase business combination. In connection with the acquisition, which included acquisition related costs of approximately $1,962,000 (consisting primarily of legal and professional services which are recorded in the accompanying statement of revenues and expenses for the year ended December 31, 2011), we funded the entire $532,255,000 cash outlay by closing a $260,000,000 three-year term loan and by financing the remaining $272,255,000 through the issuance of commercial paper and draws under existing credit facilities.

The following amounts represent the identifiable assets acquired and liabilities assumed in the Murray acquisition:

Recognized fair value amounts of identifiable assets acquired and liabilities assumed:	(in millions)
Property, plant and equipment	$ 456.7
Inventory	34.0
Other current assets	4.6
Power purchase and sale agreement	40.4
Emission credits	0.2
Current liabilities	(5.6)
Total identifiable net assets	**$ 530.3**

There was no goodwill associated with this acquisition.

We have consolidated the financial position and results of operations of Murray as of April 8, 2011. Our revenues for the year ended December 31, 2011 include $165,389,000 of non-member sales from Murray. Prior to our members taking the output from Murray, the net results of operations from Murray, including related interest costs, are being deferred as a regulatory asset as such amounts represent an additional cost incurred to acquire Murray. The regulatory asset will be amortized over the remaining life of the plant (estimated to be 30 years) beginning in 2016. For the year ended December 31, 2011, we deferred $3,536,000 in excess costs from Murray.

b. Hawk Road Energy Facility

On May 1, 2009, we acquired 100% of Heard County Power L.L.C. (Heard LLC). Heard LLC owned the Hawk Road Energy Facility, a 500 megawatt natural gas-fired peaking facility, located in Heard County. We assumed as part of the acquisition of Heard LLC an existing power purchase and sale agreement to sell 500 megawatts of capacity and associated energy to seven of our members through December 31, 2015. After 2015, the output of the Hawk Road Energy Facility will be available to all of our subscribing members.

In connection with the acquisition, we funded the entire $105,900,000 cash outlay, which included acquisition related costs and payments of approximately $900,000 (consisting primarily of legal and professional services), by issuing commercial paper. In 2011, we obtained permanent financing for the entire acquisition cost through a Rural Utilities Service-guaranteed loan from the Federal Financing Bank. The acquisition related costs of $900,000 were expensed in the second quarter of 2009.

The following amounts represent the identifiable assets acquired and liabilities assumed in the Heard LLC acquisition:

Recognized fair value amounts of identifiable assets acquired and liabilities assumed:	(in millions)
Property, plant and equipment	$ 202.7
Inventory	0.5
Current liabilities	(0.1)
Liability for power purchase and sale agreement	(98.1)
Total identifiable net assets	**$ 105.0**

There was no goodwill or gain on bargain purchase associated with this acquisition.

We consolidated the financial condition and results of operations of Heard LLC as of May 1, 2009. The impact on our revenues from the Heard LLC acquisition for the period May 1, 2009 through December 31, 2009 was $4,208,000. In May of 2010, Heard LLC was dissolved. The effects on net margin are being deferred until the end of the power purchase and sale agreement in 2015 and then they will be amortized over the remaining life of the plant.

c. Hartwell Energy Facility

On October 13, 2009, we acquired 100% of the Hartwell Energy Limited Partnership (HELP). HELP owned the Hartwell Energy Facility, a 300 megawatt oil and natural gas-fired peaking facility with two 150 megawatt combustion turbine generating units, located in Hart County. We acquired as part of the acquisition of HELP an existing power purchase and sale agreement that we had with HELP.

In connection with the acquisition, which included acquisition related costs and payments of approximately $939,000 (consisting primarily of legal and professional services), we funded the entire $109,740,000 cash outlay by issuing commercial paper. In 2011, we obtained permanent financing for the entire acquisition cost through a Rural Utilities Service-guaranteed loan from the Federal Financing Bank.

The following amounts represent the identifiable assets acquired and liabilities assumed in the HELP acquisition:

Recognized fair value amounts of identifiable assets acquired and liabilities assumed:	(in millions)
Property, plant and equipment	$ 154.7
Inventory (including fuel oil)	4.3
Other current assets	10.1
Power purchase and sale agreement	1.8
Current liabilities	(0.6)
Project level debt	(61.5)
Total identifiable net assets	**$ 108.8**

There was no goodwill or gain on bargain purchase associated with this acquisition.

We consolidated the financial position and results of operations of HELP as of October 13, 2009. The impact on our revenues from the acquisition for the period October 13, 2009 through December 31, 2009 was immaterial. In May of 2010, HELP was dissolved.

13. Quarterly financial data (unaudited)

Summarized quarterly financial information for 2011 and 2010 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(dollars in thousands)			
2011				
Operating revenues	**$ 269,774**	**$ 379,803**	**$ 432,530**	**$ 308,171**
Operating margin	**65,935**	**63,702**	**64,884**	**43,299**
Net margin	**16,110**	**12,718**	**10,408**	**(1,499)**
2010				
Operating revenues	$ 304,072	$ 326,110	$ 371,398	$ 292,565
Operating margin	65,895	59,769	63,914	49,671
Net margin	14,604	7,400	13,848	(2,119)

Our business is influenced by seasonal weather conditions. The negative net margins in the fourth quarter of 2011 and 2010 were due to reductions to revenue requirements in order to achieve the targeted margins for interest ratio of 1.14.

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRMS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Members of Oglethorpe Power Corporation

We have audited the accompanying consolidated balance sheet and consolidated statement of capitalization of Oglethorpe Power Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of revenues and expenses, patronage capital and membership fees and accumulated other comprehensive deficit, and cash flows for the years ended December 31, 2011 and 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Oglethorpe Power Corporation and subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for the years ended December 31, 2011 and 2010, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Atlanta, Georgia
March 20, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Members of Oglethorpe Power Corporation:

In our opinion, the accompanying consolidated statements of revenues and expenses, patronage capital and membership fees and accumulated other comprehensive deficit and cash flows present fairly, in all material respects, the results of operations and cash flows of Oglethorpe Power Corporation and its subsidiaries (an Electric Membership Cooperative) for the year ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
March 22, 2010

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Responsibility for Financial Statements

Our management has prepared this annual report on Form 10-K and is responsible for the financial statements and related information included herein. These statements were prepared in accordance with generally accepted accounting principles and necessarily include amounts that are based on best estimates and judgments of management. Financial information throughout this annual report on Form 10-K is consistent with the financial statements.

Management believes that our policies and procedures provide reasonable assurance that our operations are conducted with a high standard of business ethics. In management's opinion, our financial statements present fairly, in all material respects, our financial position, results of operations, and cash flows.

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2011 in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information we are required to disclose in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation under the framework in Internal Control – Integrated Framework issued by Committee of Sponsoring Organizations, our management concluded that our internal control over financial reporting was effective as of December 31, 2011 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the above-referenced evaluation by management of the effectiveness of our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2011, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our Board of Directors

Structure of our Board of Directors

Our members elect our board of directors. Our board of directors consists of directors and general managers from our members, referred to as ''member directors,'' and up to two independent outside directors. Our bylaws divide member director positions among the member scheduling groups specifically described in the bylaws, referred to as the ''member groups.'' Except for Group 5, each member group is represented by two member directors. Of each member group's two directors, one must be a general manager of a member in that member group and one must be a director of a member in that member group. Jackson Electric Membership Corporation is the only member in Group 5 and has only one director. The bylaws permit expansion of the number of member groups and changes in the composition of member groups. Formation of new member groups and changes in the composition of member groups are subject to certain required member approvals, and the requirement that the composition of the member groups at Oglethorpe, Georgia Transmission and Georgia System Operations be identical, except in cases where a member is no longer a member of one or more of Oglethorpe, Georgia Transmission or Georgia System Operations. The number of member director positions will change if additional member groups are formed or a member group ceases to exist. The bylaws also provide for three at-large member director positions which must each be filled by a director of one of our members.

In an effort to provide for equitable representation among the member groups across the boards of directors of Oglethorpe, Georgia Transmission and Georgia System Operations, the bylaws provide for certain limitations on the eligibility of directors of members of each member group to fill the three at-large member director positions. No more than one at-large member director position on our board of directors may be filled by a director of a member of any member group, no more than two directors from members of any member group may be serving in at-large member director positions on the boards of directors of Oglethorpe, Georgia Transmission and Georgia System Operations, and at least one at-large member director position on the boards of directors of Oglethorpe, Georgia Transmission or Georgia System Operations must be filled by a director of a member of each member group that has at least two members.

Pursuant to the bylaws, a member may not have both its general manager and one of its directors serve as a director of ours at the same time. Subject to a limited exception for Jackson Electric Membership Corporation, which is the sole member of one of the member groups, the bylaws prohibit any person from simultaneously serving as a director of Oglethorpe and either Georgia Transmission or Georgia System Operations.

Our bylaws require outside directors to have experience related to our business, including, without limitation, operations, marketing, finance or legal matters. No outside director may be one of our current or former officers, a current employee of ours or a former employee of ours receiving compensation for prior services. Outside directors cannot also be a director, officer or employee of Georgia Transmission, Georgia System Operations or any member. Additionally, no person who receives payment from us in any capacity other than as an outside director, including direct or indirect payments for goods and services, may serve as outside director.

The members of our board of directors serve staggered three-year terms.

Election of our Board of Directors

For a cooperative organization to maintain its status under federal tax law, it must abide by the cooperative principle of democratic control. The nomination and election of the members of our board of directors and the representation of our members by the elected directors is consistent with this principle.

Candidates for our board of directors must be nominated by the nominating committee. The nominating committee is comprised of one representative from each of our members. A majority vote of the nominating committee is required to nominate each candidate for the board of directors. Each member representative's nomination vote is weighted based on the number of retail customers served by the member. After the nominating committee nominates a candidate for a director position, the candidate must be elected by a majority vote of all of our member representatives, voting on an unweighted, one-member, one-vote basis. If the nominated candidate fails to receive a majority of the vote, the nominating committee must nominate another candidate and the member representatives will vote on that. Should that candidate also fail to receive a majority vote, this nomination and election process would be repeated until a nominated candidate is elected by a majority of the members.

Potential candidates for our board of directors must meet the requirements set forth in our bylaws, as discussed under *"Structure of our Board of Directors."* Management does not have a direct role in the nomination or election of the members of our board of directors.

Neither we, the nominating committee, nor any of our members, to our knowledge, have a policy with regard to the consideration of diversity in identifying potential candidates for our board of directors.

Board of Directors Leadership Structure

Our principal executive officer and chairman of the board positions are separate and are held by different persons. The chairman of the board and any vice-chairman of the board are elected annually by a majority vote of the members of our board of directors. Our president and chief executive officer is appointed by our board of directors. None of our executive officers nor any of our other employees are members of our board of directors.

As a cooperative, our members are our owners. Our members believe that the most effective structure to efficiently provide for their current and future needs is to take a prominent role in the direction of our business. Member control over the board of directors, and the board of directors' independence from management is beneficial and provides for member input. Direct accountability to and separation from the board of directors helps insure that management acts in the best interests of our members.

Executive Officer and Director Biographies

We are managed and operated under the direction of a president and chief executive officer. Our executive officers and directors are as follows:

Name	Age	Position
Executive Officers:		
Thomas A. Smith	57	President and Chief Executive Officer
Michael W. Price	51	Executive Vice President, Chief Operating Officer
Elizabeth B. Higgins	43	Executive Vice President, Chief Financial Officer
William F. Ussery	47	Executive Vice President, Member and External Relations
W. Clayton Robbins	65	Senior Vice President, Governmental Affairs
Charles W. Whitney	65	Senior Vice President, General Counsel
Jami G. Reusch	49	Vice President, Human Resources
Directors:(1)		
Benny W. Denham	81	Chairman and At-Large Director
Marshall S. Millwood	62	At-Large Director
Bobby C. Smith, Jr.	58	At-Large Director
George L. Weaver	63	Member Group Director (Group 1)
Danny L. Nichols	47	Member Group Director (Group 2)
H.B. Wiley, Jr.	67	Member Group Director (Group 2)
M. Anthony Ham	60	Member Group Director (Group 3)
C. Hill Bentley	64	Member Group Director (Group 3)
J. Sam L. Rabun	80	Vice-Chairman and Member Group Director (Group 4)
Jeffrey W. Murphy	48	Member Group Director (Group 4)
G. Randall Pugh	68	Member Group Director (Group 5)
Wm. Ronald Duffey	70	Outside Director

(1) Currently, our board of directors has two vacancies. We anticipate that the second member group director for Group 1 will be elected at our annual meeting to be held March 26, 2012. There are no current plans to elect a second outside director.

Executive Officer Biographies

Thomas A. Smith is the President and Chief Executive Officer of Oglethorpe and has served in that capacity since September 1999. He previously served as our Senior Vice President and Chief Financial Officer from September 1998 to August 1999, Senior Financial Officer from 1997 to August 1998, Vice President, Finance from 1986 to 1990, Manager of Finance from 1983 to 1986 and Manager, Financial Services from 1979 to 1983. From 1990 to 1997, Mr. Smith was Senior Vice President of the Rural Utility Banking Group of CoBank. Mr. Smith has a Master of Science degree in Industrial Management-Finance from the Georgia Institute of Technology, a Master of Science degree in Analytical Chemistry from Purdue University, and a Bachelor of Arts degree in Mathematics and Chemistry from Catawba College. Mr. Smith is a Director of ACES Power Marketing. Mr. Smith is also a Director of the Electric Power Research Institute and is Chairman of its Audit Committee. He is also a Director of the Georgia Chamber of Commerce and a member of the Georgia Tech Advisory Board. For the years

2007-2011, Mr. Smith was named to Georgia Trend's list of the top 100 most influential Georgians. In 2003, Mr. Smith was a recipient of the Ellis Island Medal of Honor.

Michael W. Price is our Executive Vice President and Chief Operating Officer and has served in that office since February 1, 2000. In October 2008, Mr. Price's title changed from Chief Operating Officer to his current title. Mr. Price was employed by Georgia System Operations from January 1999 to January 2000, first as Senior Vice President and then as Chief Operating Officer. He served as Vice President of System Planning and Construction of Georgia Transmission from May 1997 to December 1998. He served as a manager of system control of Georgia System Operations from January to May 1997. From 1986 to 1997, Mr. Price was employed by Oglethorpe in the areas of control room operations, system planning, construction and engineering, and energy management systems. Prior to joining Oglethorpe, he was a field test engineer with the Tennessee Valley Authority from 1983 to 1986. Mr. Price has a Bachelor of Science degree in Electrical Engineering from Auburn University. Mr. Price is a director of ACES Power Marketing, a director of National Renewables Cooperative Organization and a member of the Research Advisory Committee of the Electric Power Research Institute.

Elizabeth B. Higgins is our Executive Vice President and Chief Financial Officer and has served in that office since July 2004. In October 2008, Ms. Higgins' title changed from Chief Financial Officer to her current title. Ms. Higgins served as Senior Vice President, Finance & Planning of Oglethorpe from July 2003 to July 2004. Ms. Higgins served as Vice President of Oglethorpe with various responsibilities including strategic planning, rates, analysis and member relations from September 2000 to July 2003. Ms. Higgins served as the Vice President and Assistant to the Chief Executive Officer of Oglethorpe from October 1999 to September 2000 and served in other capacities for Oglethorpe from April 1997 to September 1999. Prior to that, Ms. Higgins served as Project Manager at Southern Engineering from October 1995 to April 1997, as Senior Consultant at Deloitte & Touche, LLP from April 1995 to October 1995, and as Senior Consultant at Energy Management Associates from June 1991 to April 1995. Ms. Higgins has a Bachelor of Industrial Engineering degree from the Georgia Institute of Technology with high honors and a Master of Business Administration degree from Georgia State University.

William F. Ussery is our Executive Vice President, Member and External Relations and has served in that office since October 2005. In October 2008, Mr. Ussery's title changed from Senior Vice President, Member and External Relations to his current title. Mr. Ussery previously served as Vice President and Assistant Chief Operating Officer of Oglethorpe from November 2003 to October 2005. Prior to joining Oglethorpe in 2001, Mr. Ussery held several key positions, including Chief Operating Officer, Vice President of Engineering and System Engineer at Sawnee Electric Membership Corporation. Mr. Ussery holds a Bachelor of Science degree in Electrical Engineering from Auburn University and an associate degree in Science from Middle Georgia College. Since March 2007, Mr. Ussery has served as a board member of the Council on Alcohol and Drug, Inc. and has served as Chairman of the Board for the past two years.

W. Clayton Robbins is our Senior Vice President, Governmental Affairs and has served in the office since October 2008. Prior to that Mr. Robbins was Senior Vice President, Government Relations and Chief Administrative Officer from July 2006 until October 2008, and as Chief Administrative Officer from January 2006 until July 2006. He also served as Senior Vice President, Administration and Risk Management of Oglethorpe from October 2002 to December 2006; and served as Senior Vice President, Finance and Administration of Oglethorpe from November 1999 to September 2002. Mr. Robbins served as Senior Vice President and General Manager of Intellisource, Inc. from February 1997 to October 1999. Prior to that, Mr. Robbins held several senior management and executive management positions at Oglethorpe beginning in 1986. Before joining Oglethorpe, Mr. Robbins spent 18 years with Stearns-Catalytic World Corporation, a major engineering and construction firm, including 13 years in management positions responsible for human resources, information systems, contracts, insurance, accounting, and project development. Mr. Robbins has a Bachelor of Arts degree in Business Administration from the University of North Carolina at Charlotte. Mr. Robbins serves as our director for the American Coalition for Clean Coal Electricity. Mr. Robbins also serves on the advisory board of FM Global Insurance Company and on the board of Niner Wine Estates, Paso Robles, in California.

Charles W. Whitney is our Senior Vice President and General Counsel and has served in that capacity since August 2009. Mr. Whitney has legal experience that spans a broad range of activities in both private practice and as chief counsel to a nuclear generating plant project. He has represented independent power producers and engineering, procurement and construction contractors in the development, construction and operation of power projects in Georgia, New York, Pennsylvania, Ohio, Michigan and Wisconsin. In private practice, Mr. Whitney's areas of focus were energy, particularly nuclear energy, regulatory, construction and labor law. His practice has also included extensive work in labor and employment discrimination; certification, enforcement and rate-making proceedings before state and federal regulators; and general trial work. In addition to practicing law for 20 years, Mr. Whitney has more than ten years of experience in senior management in the electricity industry, including both the regulated and unregulated aspects of the business. Mr. Whitney is a graduate of Wright State University and earned his Juris Doctor degree from Case Western Reserve University School of Law.

Jami G. Reusch is our Vice President, Human Resources and has served in that office since July 2004. Ms. Reusch served as Oglethorpe's Director of Human Resources and held several other management and staff positions in Human Resources prior to July 2004. Prior to joining Oglethorpe in 1994, Ms. Reusch was a senior officer in the banking industry in Georgia, where she held various leadership roles. Ms. Reusch has a Bachelor of Education degree and a Master of Human Resource Development degree from Georgia State University. She also has a Senior Professional in Human Resources certification.

Board of Directors

Director Qualifications

As required by our bylaws, all of the members of our board of directors, except for the independent outside director, are either directors or general managers of one of our members. This prerequisite helps to insure that the members of our board of directors have business experience related to electric membership corporations as well as an interest in the successful operation of our business. The members of our board of directors are elected solely by the vote of our members; neither we nor our management has any direct role in the nomination of the candidates or the election of members to our board of directors. Therefore, the following director biographies do not include a discussion of the specific experience, qualifications, attributes or skills that led our members to the conclusion that a person should serve as a director on our board of directors. For further discussion of our nomination and election process, see "– Our Board of Directors – *Election of our Board of Directors.*"

Director Biographies

Benny W. Denham is the Chairman of the Board and an at-large director. He has served on our board of directors since December 1988. His present term will expire in March 2013. Mr. Denham has been co-owner of Denham Farms in Turner County, Georgia since 1980. Mr. Denham is a director of Irwin Electric Membership Corporation.

Marshall S. Millwood is an at-large director. He has served on our board of directors since March 2003. His present term will expire in March 2012. He is also a member of the construction project committee. He has been the owner and operator of Marjomil Inc., a poultry and cattle farm in Forsyth County, Georgia, since 1998. He is a director of Sawnee Electric Membership Corporation.

Bobby C. Smith, Jr. is an at-large director. He has served on our board of directors since May 2008. His present term will expire in March 2014. He is also a member of the construction project committee. Mr. Smith is a farmer. He is a member of the board of Planters Electric Membership Corporation. He is also a member of the board of the Screven County Industrial Development Authority and of the Sylvania Lions Club.

George L. Weaver is a member group director (group 1). He has served on our board of directors since March 2010. His present term will expire in March 2013. He is also a member of the Compensation Committee. Mr. Weaver has been employed by Central Georgia Electric Membership Corporation since 1970 and is currently serving as President. Mr. Weaver is a current director of Southeastern Data Cooperative and former director of First Georgia Community Corporation and Federated Rural Electric Insurance Corporation.

Danny L. Nichols is a member group director (group 2). He has served on our board of directors since March 2011. His present term will expire in March 2014. Mr. Nichols is a member of the construction project committee. Mr. Nichols is the General Manager of Colquitt Electric Membership Corporation.

H.B. Wiley, Jr. is a member group director (group 2). He has served on our board of directors since March 2003. His present term will expire in March 2012. He is also a member of the audit committee. Mr. Wiley previously served as a member of the board of directors from July 1994 until March 1997. Mr. Wiley has been an associate broker in real estate since 1994. Prior to that time, he owned and operated a dairy farm in Oconee County, Georgia from 1973 to 1994. During that time he served on the board of Atlanta Dairies Cooperative and Georgia Milk Producers Board. Mr. Wiley has been a director of Walton Electric Membership Corporation since June 1993, and served as Chairman from June 2000 to June 2003 and June 2009 to June 2011. Mr. Wiley has a Bachelor of Science degree in Agriculture from the University of Georgia. Mr. Wiley served in the U.S. Army Engineers from 1968 to 1971 and is a Vietnam veteran.

M. Anthony Ham is a member group director (group 3). He has served on our board of directors since March 2004. His present term will expire in March 2014. He is also a member of the compensation committee. Mr. Ham operates Tony Ham Elite Property Services. In December 2008, Mr. Ham left his position as the Clerk of the Superior and Juvenile Court in Brantley County, Georgia after 20 years of service. He is a director of Okefenoke Rural Electric Membership Corporation and was appointed Secretary and Treasurer in 2007.

C. Hill Bentley is a member group director (group 3). He has served on our board of directors since March 2004. His present term will expire in March 2013. He is also a member of the audit committee. He is the Chief Executive Officer of Tri-County Electric Membership Corporation. He is on the Board of Directors of the Georgia Cooperative Council and a member of the board of directors of the Central Georgia Technical College Foundation. Mr. Bentley is a member of the Georgia Chamber of Commerce and is past President of the Jones County Chamber of Commerce. He serves on both the Government Relations Committee and Territorial Integrity Fund Committee for Georgia EMC. Mr. Bentley is a member, and a past President, of the Georgia Rural Electric Managers Association and a vice-president of the Rural Electric Managers Development Council. He was also appointed by the Governor to serve as a member of the Middle Georgia Regional Commission Council and is on the Business Advisory Council for Georgia College and State University.

J. Sam L. Rabun is the Vice-Chairman of the Board and a member group director (group 4). He has served on our board of directors since March 1993. His present term will expire in March 2013. He is also the chairman of the compensation committee. He has been the owner and operator of a farm in Jefferson County, Georgia since 1979. Mr. Rabun served as the President of the Board of Jefferson Energy Cooperative from 1993 to 1996, was employed as General Manager from 1974 to 1979 and as Office Manager and Accountant from 1970 to 1974. He currently serves on the board of Jefferson Energy Cooperative. Mr. Rabun is Vice-Chairman of the Board of the Georgia Energy Cooperative.

Jeffrey W. Murphy is a member group director (group 4). He has served on our board of directors since March 2004. His present term will expire in March 2012. He is also a member of the audit committee. Mr. Murphy has been the President and Chief Executive Officer of Hart Electric Membership Corporation since May 2002. He is also the Secretary of the Georgia Energy Cooperative.

G. Randall Pugh is a member group director (group 5). He has served on our board of directors since May 2008. His present term will expire in March 2014. He is also the chairman of the construction project committee. Mr. Pugh is the President and Chief Executive Officer of Jackson Electric Membership Corporation, prior to which he served as General Manager of Walton Electric Membership Corporation. From 2006 to 2011, Mr. Pugh was on the Board of First Georgia Banking Company (Jackson and Banks County) and from 2007 to 2011, he served on the Board of Directors of and Chairman of First Georgia Bankshares Holding Company. He is Chairman of the Georgia System Operations Audit Committee. He also serves on the Board of Directors of Green Power Electric Membership Corporation and Georgia System Operations. Mr. Pugh is a member of the Executive Board of the Northeast Georgia Council of the Boy Scouts of America. He is a member of the board and serves as Chairman of the Jackson County, Georgia, Water and Sewer Authority. He also is a member and past President of the Jackson County Chamber of Commerce and of the Jefferson Rotary Club.

Wm. Ronald Duffey is an outside director. He has served on our board of directors since March 1997. His present term will expire in March 2012. He is also the chairman of the audit committee. Mr. Duffey is the retired Chairman of the Board of Directors of Peachtree National Bank in Peachtree City, Georgia, a wholly owned subsidiary of Synovus Financial Corp. Prior to his employment in 1985 with Peachtree National Bank, Mr. Duffey served as Executive Vice President and Member of the Board of Directors for First National Bank in Newnan, Georgia. He holds a Bachelor of Business Administration degree from Georgia State College with a concentration in finance and has completed banking courses at the School of Banking of the South, Louisiana State University, the American Bankers Association School of Bank Investments, and The Stonier Graduate School of Banking, Rutgers University. Mr. Duffey is a director of Piedmont-Newnan Hospital. Mr. Duffey is also a member of the board of directors of the Georgia Chamber of Commerce and of Piedmont Healthcare, where he serves on both the audit committee and the finance committee.

Committees of the Board of Directors

Our board of directors has established an audit committee, a compensation committee and a construction project committee. The audit committee, the compensation committee and the construction project committee each operate pursuant to a committee charter and/or policy. We do not have a nominating and corporate governance committee; directors are nominated by representatives from each member whose weighted nomination is based on the number of retail customers served by each member, and after nomination, elected by a majority vote of the members, voting on a one-member, one-vote basis.

Audit Committee. The audit committee is responsible for assisting the board of directors in its oversight of all material aspects of our financial reporting functions. Its responsibilities include selecting our independent accountants, reviewing the plans, scope and results of the audit engagement with our independent accountants, reviewing the independence of our independent accountants and reviewing the adequacy of our internal accounting controls. The members of the audit committee are currently Wm. Ronald Duffey, Jeffrey W. Murphy, C. Hill Bentley and H. B. Wiley, Jr. Mr. Duffey is the chairman of the audit committee. The board of directors has determined that Mr. Duffey qualifies as an independent audit committee financial expert.

Compensation Committee. The compensation committee is responsible for monitoring adherence with our compensation programs and recommending changes to its compensation programs as needed. Currently, the members of the compensation committee are J. Sam L. Rabun, M. Anthony Ham and George L. Weaver. Mr. Rabun is the chairman of the compensation committee.

Construction Project Committee. The construction project committee is responsible for reviewing and making recommendations to our board of directors with regards to major actions or commitments relating to new power plant construction projects and certain existing plant modification projects. Its responsibilities include reviewing and recommending to our board of directors final plant sites, project budgets (including certain modifications to project budgets) and project construction plans, and a quarterly reviewing of and reporting on the status of projects. The members of the construction project committee are currently G. Randall Pugh, Marshall S. Millwood, Danny L. Nichols and Bobby C. Smith, Jr. Mr. Pugh is the chairman of the construction project committee.

Board of Directors' Role in Risk Oversight

Our board of directors and the audit committee both actively oversee our exposure to risks in our business. Our board of directors has adopted corporate policies regarding management of risks related to financial management, capital investment and the use of derivatives. One of the primary risk oversight activities of the board of directors is to hold an annual strategic planning session to review potentially material threats and opportunities to our business. To facilitate this review, management develops a comprehensive strategic issues matrix. The strategic issues matrix identifies, describes, assesses and classifies the potential impact or magnitude, and outlines corporate strategies for addressing, potentially material threats and opportunities to our business. Management also develops and typically shares a corporate risk map with our board of directors during this session. The corporate risk map depicts the probability of occurrence and the potential severity for each significant corporate risk. During this session, our board of directors reviews these analyses and affirms or assists management with developing strategies to address these strategic risks and opportunities.

At each regular meeting of the board of directors, management provides the board with reports on significant changes related to the top strategic risks and opportunities facing us and a revised version of the strategic issues matrix that highlights any revisions to the matrix. The audit committee chairman also provides the board of directors with updates on overall corporate risk exposure. Furthermore, the board of directors receives risk analysis reports that identify key risks that could create variances from our approved annual budget and long-range forecasts and as well as discussing the potential likelihood and magnitude of changes to member rates related to these risks based on scenario modeling.

Our board of directors has delegated direct oversight of corporate risk management to the audit committee. Pursuant to its charter, the audit committee reviews our business risk management process, including the adequacy of our overall control environment, in selected areas that represent significant financial and business risks. The audit committee receives regular reports on the activities of the risk management committee, which are described below, as well as quarter-end reports, which include changes to derivative hedge positions and overall corporate risk exposure. The risk management and compliance committee, comprised of our chief executive officer, chief operating officer, chief financial officer, and the executive vice president of member and external relations, provides general oversight over all of our risk management and compliance activities, including but not limited to commodity trading, fuels management, insurance procurement, debt management, investment portfolio management and environmental compliance and electric reliability compliance. The risk management committee has implemented comprehensive policies and procedures, consistent with current board policies, which govern our activities pertaining to market and other risks. For further discussion about our risk management committee and its activities, see "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK."

Code of Ethics and Code of Conduct

We have adopted a Code of Conduct that applies to all our employees, including our principal executive, financial and accounting officers. Our Code of Conduct is available at our website, www.opc.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Executive Summary

The philosophy and objective of our compensation and benefits program is to establish and maintain competitive total compensation programs that will attract, motivate and retain the qualified skilled workforce necessary for our continued success. The compensation committee of the board of directors has the primary responsibility for establishing, implementing and monitoring adherence with our compensation programs. To help align executive officers' interests with those of our members, we have designed a significant portion of our cash compensation program as a pay for performance based system that rewards executive officers based on our success in achieving the corporate goals discussed below. To remain competitive, we review our total compensation program against generally available market data as a check to gain a general understanding of current compensation practices.

Components of Total Compensation

The compensation committee determined that compensation packages for the fiscal year ended December 31, 2011 for our executive officers should be comprised of the following three primary components:

- Annual base salary,
- Performance pay, which consists of a cash award based on the achievement of corporate goals, and
- Benefits, which consist primarily of health, welfare and retirement benefits.

Each of our executive officers has an employment agreement that provides for minimum annual base salary and performance pay. See "– *Employment Agreements*."

Since we are an electric cooperative, we do not have any stock and as a result do not have equity-based compensation programs.

Base Salary. Base salary is the primary component of our compensation program and it is set at a level to attract and retain executives who can lead us in meeting our corporate goals. Base salary levels are set based on several factors, including but not limited to the position's duties and responsibilities, the individual's value and contributions to the company, work experience and length of service.

Performance Pay. Performance pay is designed to reward executive officers based on the achievement of our strategic, operational and financial goals. The corporate goals selected are designed to align the interests of our executive team and employees with the interests of our members. The compensation committee believes it is appropriate to consider only corporate goal achievement when determining executive officers' performance pay because our corporate philosophy focuses on teamwork, and we believe that better results evolve from mutual work towards common goals. Furthermore, the compensation committee believes that our achievement of these corporate goals will correspond to high company performance, and our executive officers are responsible for directing the work and making the strategic decisions necessary to successfully meet these goals. Each executive officer is eligible to receive up to 20% of his or her base salary as a performance bonus based entirely on the achievement of corporate goals.

Importantly, our executive officers cannot help us meet our goals and improve performance without the work of others. For this reason, the performance goals set at the corporate level are the same for both executive officers and all non-executive employees.

Benefits. The benefits program is designed to allow executive officers to choose the benefit options that best meet their needs. Our president and chief executive officer recommends changes to the benefits program or level of benefits that all executive officers, including our president and chief executive officer, receive to the compensation committee. The compensation committee then reviews and recommends changes to the board of directors for its approval. To meet the health and welfare needs of its executive officers at a reasonable cost, we pay for 80-85% of an executive officer's health and welfare benefits. Our president and chief executive officer decides our exact cost sharing percentage.

We also provide retirement benefits that allow executive officers the opportunity to develop an investment strategy that best meets their retirement needs. We will contribute up to $0.75 of every dollar an executive officer contributes to his or her retirement plan, up to 6% of an executive officer's pay per period, and will contribute an additional amount equal to 8% of an executive officer's pay per period. See "– Nonqualified Deferred Compensation" below for additional information regarding our contributions to our executive officers' retirement plans.

Perquisites. We provide our executive officers with perquisites that we and the compensation committee believe are reasonable and consistent with our overall compensation program. The most significant perquisite provided to our executive officers is a monthly car allowance, the amount of which is based upon the executive officer's position. Our president and chief executive officer approves the executive officers eligible for car allowances and reports this information to the compensation committee. The car allowance for our president and chief executive officer is included in his employment agreement. The compensation committee periodically reviews the levels of perquisites provided to executive officers.

Bonuses. Our practice has been to, on infrequent occasions, award cash bonuses to senior management related to exemplary performance. Our compensation committee determines the bonus criteria and may issue discretionary bonuses to our president and chief executive officer. Our president and chief executive officer determines the bonus criteria and may issue discretionary bonuses to other members of senior management.

Establishing Compensation Levels

Role of the Compensation Committee. The compensation committee annually reviews each of the components of our compensation program for our officers, directors and employees and recommends any changes to our board of directors for approval. In order to have a compensation program that is internally consistent and equitable, the compensation committee considers several subjective and objective factors when determining the compensation program. The compensation committee currently reviews and sets the compensation for our president and chief executive officer. Some of the factors reviewed include the position's duties and responsibilities, the individual's job performance, experience, longevity of service and overall value provided for our members.

The compensation committee also approves our performance pay program, including the corporate goals related to such program. Bonuses for the president and chief executive officer are also at the discretion of the compensation committee. The compensation committee receives a comprehensive report on an annual basis regarding all facets of our compensation program. The compensation committee also reviews the employment contracts each year and makes an affirmative decision whether they should be extended.

The compensation committee operates pursuant to a statement of functions that sets forth the committee's objectives and responsibilities. The compensation committee's objective is to review and recommend to the board of directors for approval any changes to various compensation related matters, as well as any significant changes in benefits cost or level of benefits, for the members of the board of directors, the executive officers, and our other employees. The compensation committee annually reviews the statement of functions and makes any necessary revisions to ensure its responsibilities are accurately stated.

Role of Management. Our president and chief executive officer is the key member of management involved in our compensation process. He annually reviews the compensation of our other executive officers and in certain circumstances provides an upward adjustment to the executive officers' base salary. Our president and chief executive officer reports the executive officers' salaries to the compensation committee annually. Some of the factors the president and chief executive officer considers include the person's relative responsibilities and duties, experience, job performance, longevity of service and overall value provided for our members.

Our president and chief executive officer, together with the other executive officers, identifies corporate performance objectives that are used to determine performance pay amounts. He and our vice president, human resources present these goals to the compensation committee. The compensation committee then reviews and approves the goals and presents them to the board of directors for final approval.

Role of the Board of Directors. Our board of directors must approve changes recommended by the compensation committee. These approvals include the compensation of our president and chief executive officer and the components of our compensation program each year.

Role of Generally Available Market Data. To confirm that our compensation remains competitive, we review standardized surveys to check our total compensation program against other companies in the utility industry of a similar size. We do not benchmark against such data; rather we utilize these surveys to gain a general understanding of current compensation practices and better understand and compare the components of our compensation program. The surveys we review are generally available, and we have not hired a compensation consultant to provide us with information on executive compensation data. Compensation levels other companies pay to their executives do not drive our compensation decisions, and we do not target a specific market percentile for our executive officer compensation.

Corporate Goals for Performance Pay

We choose to tie performance compensation to selected corporate goals that most appropriately measure our achievement of our strategic objectives. For 2011, our performance measures were divided into the following categories: i) operations, ii) financial, iii) quality, iv) corporate compliance, v) safety and vi) future generation. Targeted performance measures in these categories are designed to help us accomplish our corporate goals which will benefit our members, employees and promote responsible environmental stewardship.

The maximum performance pay each executive officer can receive is 20% of his or her salary and in order to receive the full 20%, 100% of the performance measures must be achieved. The performance measures are weighted to align with our current strategic focus, and each goal is reviewed annually, and adjusted if necessary in order to reflect any changes in our strategic focus. For example, in 2011 the weighting for our operations related goals increased to 35% from 28% in 2010, while weighting for future generation decreased to 2% in 2011 from 20% in 2010. We also review and refine these goals annually and make adjustments as necessary to ensure that we are consistently stretching our expectations and performance. Although some performance measures may stay the same, the applicable threshold may become more difficult. The following provides an overview of the purposes of each category of our corporate goals:

Operations. The operations goals measure how well each of our operating plants responds to system requirements. In order to optimize generation for system load requirements, we generally dispatch the most efficient and economical generation resources first. If the preferred generation resource is not available when called upon, we must resort to a more expensive alternative. Most of the performance measures in this category, including start reliability and equivalent forced outage rate are measured against industry averages and the applicable thresholds are set above average. In order to meet these standards, we must properly operate and maintain these facilities, which minimizes long-term maintenance and replacement energy costs. Certain operational goals take into account performance standards as required by contracts related to the facility operations. This corporate goal excludes performance measures related to facilities operated by Georgia Power as we do not direct operations at those facilities. Our achieving operational excellence at the corporate level results in the most reliable, efficient and lowest cost power supply for our members.

Financial. Our financial goals are divided into two components, (i) a cost savings and reduction goal and (ii) a value added and risk reduction goal. The cost savings and reduction goal is designed to encourage staff to identify and implement strategies that result in cost savings or cost reductions in either the current year or in the long-term. Any cost savings included in this goal must be over and above what would generally be expected. The value added and risk reduction goal encourages staff to develop programs that add value to our resources and reduce risk exposure. Some of these programs are subjective and not readily quantifiable in dollar terms and therefore discretion as to the achievement of the value added component is placed with the compensation committee. Our financial goals provide direct benefits to our members by lowering power costs and adding value to our assets.

Quality. Quality is a subjective goal that is intended to measure the satisfaction of our members with our efforts, initiatives, responsiveness and other intangibles that are not readily quantified. Performance on this goal is based on semi-annual surveys submitted by the members of the board of directors who, except for our outside director, are general managers or directors of our members. The results of the surveys are averaged to determine the total quality result. In order to achieve the maximum award, we must receive a 100% rating from every member of the board of directors on both surveys, an extremely high standard that has yet to be achieved.

Corporate Compliance. Our corporate compliance goals are divided into three categories – environmental, reliability and development of our corporate compliance program. The environmental goals incentivize our commitment to responsible environmental stewardship while providing reliable and affordable energy. We measure our performance by the number of environmental incidents, such as spills, which not only increase costs for our members but may cause environmental damage. Reliability compliance is measured by considering whether we have received notice of any violations from electric reliability organizations. To achieve the maximum awards for the environmental and reliability categories, we must achieve perfection, meaning no spills or notices of violation. Our corporate compliance program was designed to minimize business risks related to non-compliance with general laws, rules and regulations, contracts and other business concerns and minimize any economic consequences. The related goal measures our performance developing and implementing this program.

Safety. Our safety goals provide employees a financial incentive to focus on a safe workplace environment, which increases employee morale and minimizes lost time. Safety performance is measured by comparing incident rates in our work environment against national incident rates compiled by the U.S. Department of Labor's Bureau of Labor Statistics.

Future Generation. In order to continue to meet the generation needs of our members, we look to develop future generation resources as requested by our members. Future generation goals are often based on significant project milestones to meet the applicable commercial operation dates. In 2011, we began planning for the potential development of a combustion turbine facility and assigned a goal related to this project.

Calculation of Performance Pay Earned

Performance pay earned by our executive officers is based entirely on our success in achieving each of our corporate goals. Annually, our board of directors approves a weighted system for determining performance pay whereby we assign a percentage to each of the goals, as noted below. Based on the achievement of each category, a percentage of the weighted goal is available as performance pay to our executive officers. If the threshold standard is met for the performance measure, then 25% of the performance pay for that metric will be awarded. The percentages earned will increase, generally on a pro rata basis, to 100% of each performance measure if the maximum level is achieved. If the performance level falls below the threshold, there is no payout associated with the applicable goal. Threshold and maximum levels are reviewed annually and generally reset to demand ever improving corporate performance. Meeting the applicable thresholds is not guaranteed and requires diligence and hard work. Exceptional performance is required to reach the maximum goals.

For each executive officer, we multiply 20% of his or her base salary by the achievement percentage to determine his or her performance bonus. For example, if we had a 90% corporate goal achievement rate in a given year, each executive officer's performance bonus would equal (base salary × 20%) × (90%).

Assessment of Performance of 2011 Corporate Goals

The specific corporate performance measures, thresholds, maximums and results for our executive officers' 2011 performance pay were the following:

Performance Category/Description	Performance Measure	Threshold	Maximum	2011 Result	Weight	Weighted Goal Achieved
Operations						
Rocky Mountain	Start Reliability	99.75%	100.0%	99.9%	3.0%	2.4%(1)
	Peak Season Availability	99.00%	100.0%	96.7%	4.0%	1.0%(1)
	Equivalent Forced Outage Rate	1.3-2.6%	0.3%	3.2%	4.0%	2.5%(1)
Combustion Turbine	Start Reliability	96.31-98.03%	100.0%	97.5%	4.0%	2.7%(1)
Operations	Peak Season Availability	99.0%	100.0%	89.9%	9.0%	5.1%(1)
Chattahoochee	Availability	96.5-98.0%	100.0%	90.0%	4.0%	2.6%(1)
	Dispatch Order Percentage	95.0%	100.0%	96.7%	3.0%	1.3%(1)
Murray	Seasonable Availability Percentage	95.5-97.0%	99.0-100.0%	99.4%	2.0%	2.0%
	Profitability	$ 5,000,000	$ 10,000,000	$ 8,056,028	2.0%	1.4%
Financial						
Cost Savings/ Reduction Programs and Activities	Current-Year Savings	$ 1,000,000	$ 10,000,000	$ 11,901,088	10.0%	10.0%
	Long-Term Savings	$ 5 million	$ 35 million	$ 39,609,797	10.0%	10.0%
Value Added/Risk Reduction	Qualifying Programs	Discretion of Compensation Committee			3.0%	3.0%
Quality						
Member Satisfaction	Board of Directors Survey	80%	100%	95.6%	20.0%	16.7%
Corporate Compliance						
Environmental Compliance	Final Notices of Violation	1 (if fine is less than $5,000)	0	0	3.0%	3.0%
	Letters of Non-Compliance	2	0	0	2.0%	2.0%
	Reportable Spills	0	0	0	2.5%	2.5%
	Non-Reportable Spills/Clean-Ups (more than $5,000 to clean-up)	1	0	1	1.5%	0.0%
Electric Reliability Standards Compliance	Final Notices of Violation	1 (if penalty is $25,000 or less)	0	0	2.0%	2.0%
	Develop and Implement Internal Reliability Standards Compliance Program	N/A	N/A	N/A	1.0%	1.0%
Corporate Compliance Development Program	Develop and Implement Internal Code of Conduct	N/A	N/A	N/A	3.0%	3.0%
Safety						
	Incidents Recordable Injuries and Illnesses	4	0	1	2.0%	1.5%
	Incidents of Lost Work Cases	2	0	0	2.0%	2.0%
	Maintain Rural Electric Safety Accreditation	N/A	N/A	Yes	1.0%	1.0%
Future Generation						
Potential Combustion Turbine Units	Complete Site Selection	By Oct. 7	By Sept. 9	By Sept. 9	2.0%	2.0%
Total					**100%**	**80.7%**

(1) Operations goals apply to individual units of each generation facility. The thresholds and performance results provided in this summary table are aggregated results based on all of the generating units within the category.

As noted above, we achieved 80.7% of our corporate goals for 2011. As a result of achieving 80.7% of our corporate goals, each of our executive officers received performance pay in an amount equal to 80.7% of 20% of his or her base salary. Set forth below is a table showing 2011 performance pay figures for each of our executive officers:

Executive Officer	Performance Pay*
Mr. Smith	$ 96,840
Mr. Price	56,064
Ms. Higgins	56,064
Mr. Ussery	43,223
Mr. Whitney	49,631

* Performance pay was calculated based on base salaries as of December 31, 2011. Actual compensation earned in 2011 is reported in the Summary Compensation Table below.

Employment Agreements

General

We have an employment agreement with each of our executive officers. We negotiated each of these employment agreements on an arms-length basis, and the compensation committee determined that the terms of each agreement are reasonable and necessary to ensure that our executive officers' goals are aligned with our members' and that each performs his or her respective role while acting solely in our members' best interests. The compensation committee reviews these agreements annually last reviewed these employment agreements in November 2011.

We entered into our current employment agreement with Mr. Smith on January 1, 2007. Pursuant to the automatic renewal provision of his employment agreement, the current term of the agreement extends through December 31, 2014 and will continue to automatically renew for successive one-year periods unless either party provides written notice not to renew the agreement twenty-five months before the expiration of any extended term. No such notice has been provided. Mr. Smith's minimum annual base salary under his agreement is $440,870, and is subject to review and upward adjustment by our board of directors. Mr. Smith is eligible for an annual bonus and to participate in incentive compensation plans generally available to similarly situated employees, determined by our board of directors in its sole discretion. Mr. Smith is also entitled to an automobile or an automobile allowance during the term of the agreement. Mr. Smith's employment agreement contains severance pay provisions. Details regarding the severance pay provisions of the agreement are provided under "– Severance Arrangements."

We also have employment agreements with Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney. Pursuant to the automatic renewal provisions of these employment agreements, the current term of each agreement extends through December 31, 2013 and will continue to automatically renew for successive one-year periods unless either party provides written notice not to renew the agreement thirteen months before the expiration of any extended term. No such notices have been provided.

Minimum annual base salaries under these agreements are $255,116 for Mr. Price, $246,887 for Ms. Higgins, $171,700 for Mr. Ussery, and $300,000 for Mr. Whitney. Salaries are subject to review and possible adjustment as determined by the president and the chief executive officer. Each executive is also eligible for an annual bonus and to participate in incentive compensation plans generally available to similarly situated employees, determined by us in our sole discretion. The employment agreements with Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney contain severance pay provisions. Details regarding the severance pay provisions of the agreements are provided under "– Severance Arrangements" below.

Assessment of Severance Arrangements

Pursuant to their respective employment agreements, each of our executive officers is entitled to certain severance payments and benefits in the event they are terminated not for cause or they resign for good reason.

In determining that the president and chief executive officer's employment agreement was appropriate and necessary, the compensation committee considered Mr. Smith's role and responsibility within Oglethorpe in relation to the total amount of severance pay he would receive upon the occurrence of a severance event. The committee also considered whether the amount Mr. Smith would receive upon severance was appropriate given his total annual compensation. Upon review, the compensation committee determined that a maximum amount of severance compensation equal to a maximum of two year's compensation, plus benefits as described below, was an appropriate amount of severance compensation for Mr. Smith. The compensation committee believes that entering into a severance agreement with our president and chief executive officer is beneficial because it gives us a measure of stability in this position while affording it the flexibility to change management with minimal disruption, should our board of directors ever determine such a change to be necessary and in our best interests. The compensation committee considered an amount equal to up to two years of compensation and benefits to be an appropriate amount to address competitive concerns and offset any potential risk Mr. Smith faces in his role as our president and chief executive officer. Furthermore, it should be noted that we do not compensate our president and chief executive officer using options or other forms of equity compensation that typically lead executives to accumulate large amounts of wealth during employment.

The compensation committee also considered the total amount of compensation each of the other executive officers would receive upon the occurrence of a severance event. The compensation committee determined that it was also appropriate for our other executive officers to receive severance compensation equal to one year's compensation, plus benefits as described below, because such agreements provide a measure of stability for both us and our other executive officers. In addition, like our president and chief executive officer, our other executive officers are not compensated using options or other forms of equity compensation that lead to significant wealth accumulation. Therefore, the compensation committee believed such severance compensation is necessary to address competitive concerns and offset any potential risk our executive officers face in the course of their employment.

Compensation Committee Report

The Compensation Committee of Oglethorpe Power Corporation has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2011 for filing with the SEC.

Respectfully Submitted,

The Compensation Committee

J. Sam L. Rabun
M. Anthony Ham
George L. Weaver

Compensation Committee Interlocks and Insider Participation

J. Sam L. Rabun, M. Anthony Ham, Larry N. Chadwick and George L. Weaver served as members of our compensation committee in 2011.

George L. Weaver is a director of ours and also the president of Central Georgia Electric Membership Corporation. Central Georgia is a member of ours and has a wholesale power contract with us. Central Georgia's payments of $31.7 million to us in 2011 under its wholesale power contract accounted for 2.3% of our total revenues.

Summary Compensation Table

The following table sets forth the total compensation paid or earned by each of our executive officers for the fiscal years ended December 31, 2011, 2010 and 2009.

Name and Principal Position	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	All Other Compensation(1)	Total
Thomas A. Smith	2011	$ 595,792	$ –	$ 96,840	$ 98,681	$ 791,313
President and Chief Executive Officer	2010	575,030	50,000	101,386	92,965	819,381
	2009	570,625	–	100,696	91,557	762,878
Michael W. Price	2011	345,133	–	56,064	62,660	463,857
Executive Vice President and Chief Operating Officer	2010	334,000	6,680	58,918	53,207	452,805
	2009	331,666	–	58,517	52,123	442,306
Elizabeth B. Higgins	2011	345,133	–	56,064	53,726	454,923
Executive Vice President and Chief Financial Officer	2010	334,000	6,680	58,918	52,243	451,841
	2009	331,666	–	58,517	51,786	441,969
William F. Ussery	2011	266,500	–	43,223	44,470	354,193
Executive Vice President, Member and External Relations	2010	260,124	–	45,864	43,568	349,556
	2009	258,333	–	45,552	44,003	347,888
Charles W. Whitney(2)	2011	306,250	–	49,631	57,080	412,961
Senior Vice President, General Counsel	2010	300,144	–	52,920	31,664	384,728
	2009	112,500	–	17,518	33,213	163,231

(1) Figures for 2011 consist of customary holiday gifts, service awards, matching contributions made by Oglethorpe under the 401(k) Retirement Savings Plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney of $11,025, $11,025, $11,025, $8,387 and $11,025, respectively; contributions made by Oglethorpe under the 401(k) Retirement Savings Plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney of $19,600, $19,600, $19,600, $19,600 and $19,600, respectively; contributions by Oglethorpe to a nonqualified deferred compensation plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney, respectively of $41,058, $13,772, $13,259, $5,389 and $9,134; a car allowance of $12,000, $9,000, $9,000, $9,000 and $9,000 for Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney, respectively; and insurance premiums paid on term life insurance on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney of $3,870, $1,765, $767, $1,769 and $8,246, respectively and payment for unused paid time off for Mr. Smith and Mr. Price in the amount of $11,053 and $6,423, respectively.

(2) Mr. Whitney became an Oglethorpe employee in August 2009.

The following table sets forth the threshold, or minimum, and maximum awards available to the executive officers listed in the Summary Compensation Table with respect to performance pay for the fiscal year ended December 31, 2011.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Threshold	Estimated Future Payouts Under Non-Equity Incentive Plan Awards: Maximum
Thomas A. Smith President and Chief Executive Officer	N/A	$ 22,440	$ 120,000
Michael W. Price Executive Vice President and Chief Operating Officer	N/A	12,991	69,472
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	N/A	12,991	69,472
William F. Ussery Executive Vice President, Member and External Relations	N/A	10,016	53,560
Charles W. Whitney Senior Vice President and General Counsel	N/A	11,501	61,500

For an explanation of the criteria and formula used to determine the awards listed above, please refer to "– Compensation Discussion and Analysis – *Assessment of Performance of 2011 Corporate Goals*."

Nonqualified Deferred Compensation

We maintain a Fidelity Non-Qualified Deferred Compensation Program for each of the executive officers in the table below. This non-qualified deferred compensation program serves as a vehicle through which we can continue our employer retirement contributions to our executive officers beyond the IRS salary limits on the retirement plan ($245,000 as indexed).

From 2001 through 2004, Mr. Smith received deferred compensation benefits through his participation in our Executive Supplemental Retirement Plan. Mr. Smith has not received any benefits pursuant to this plan since 2004 and none of our other executive officers are currently participating in this plan.

The following table sets forth our contributions for the fiscal year ended December 31, 2011 along with aggregate earnings for the same period.

Name	Registrant Contributions in Last FY[1]	Aggregate Earnings in Last FY[2]	Aggregate Balance at Last FYE
Thomas A. Smith President and Chief Executive Officer	$ 41,058	$ (12,000)	$ 523,270
Michael W. Price Executive Vice President and Chief Operating Officer	13,772	1,315	69,166
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	13,259	(1,066)	64,700
William F. Ussery Executive Vice President, Member and External Relations	5,389	(249)	19,135
Charles W. Whitney Senior Vice President and General Counsel	9,134	170	9,304

(1) All registrant contribution amounts shown have been included in the "All Other Compensation" column of the Summary Compensation Table above and are limited to the Fidelity Non-Qualified Deferred Compensation Program.

(2) A participant's accounts under the deferred compensation program are invested in the investment options selected by the participant. The accounts are credited with gains and losses actually experienced by the investments.

Severance Arrangements

Pursuant to the terms of his employment agreement, Mr. Smith will be entitled to a lump-sum severance payment upon the occurrence of any of the following events: (1) we terminate his employment without cause; or (2) he resigns due to a demotion or material reduction of his position or responsibilities, reduction of his base salary, or a relocation of his principal office by more than 50 miles. The severance payment will equal Mr. Smith's then current base salary through the rest of the term of the agreement (with a minimum of one year's pay and a maximum of two years' pay), and is payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. In addition, Mr. Smith will be entitled to outplacement services and an amount equal to his costs for medical and dental continuation coverage under COBRA, each for the longer of one year or the remaining term of the agreement. Severance is payable only if Mr. Smith signs a form releasing all claims against us within 45 days after his termination date. The maximum severance that would be payable to Mr. Smith in the circumstances described above is $1,310,536.

Pursuant to the terms of their employment agreements, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney will each be entitled to a lump-sum severance payment if we terminate the executive without cause or if the executive resigns after a demotion or material reduction of his or her position or responsibilities, a reduction of his or her base salary, or a relocation of his or her principal office by more than 50 miles. The severance payment will equal the one year of the executive's then current base salary, payable six months after the executive's termination date. In addition, the executive will be entitled to six months of outplacement services and an amount equal to the executive's cost for medical and dental continuation coverage under COBRA for six months. Severance is payable only if the executive signs a form releasing all claims against us within 45 days after his or her termination date. The maximum severance that would be payable to Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Whitney in the circumstances described above is $380,286, $380,411, $291,379 and $335,918, respectively.

Compensation Policies and Practices As They Relate to Our Risk Management

We believe that our compensation policies and practices for all employees, including executive officers, do not create risks that are reasonably likely to have a material adverse effect on us.

Director Compensation

The following table sets forth the total compensation paid or earned by each of our directors for the fiscal year ended December 31, 2011.

Name	Total Fees Earned or Paid in Cash
Member Directors	
Benny W. Denham, Chairman	$ 13,640
J. Sam L. Rabun, Vice-Chairman	$ 17,900
C. Hill Bentley	$ 11,600
Larry N. Chadwick	$ 13,300(1)
Rick L. Gaston	$ 2,000(2)
M. Anthony Ham	$ 13,900
Marshall S. Millwood	$ 13,500
Jeffrey W. Murphy	$ 11,600
Danny L. Nichols	$ 10,000
G. Randall Pugh	$ 11,700(3)
Bobby C. Smith, Jr.	$ 14,100
George L. Weaver	$ 12,100
H.B. Wiley, Jr.	$ 13,400
Outside Directors	
Wm. Ronald Duffey	$ 29,100

(1) On March 1, 2012, Mr. Chadwick resigned from his position on the board of directors of Cobb Electric Membership Corporation and became ineligible to serve on our board of directors.

(2) On January 31, 2011, Mr. Gaston retired from his position as General Manager of Colquitt Electric Membership Corporation and became ineligible to serve on our board of directors.

(3) Mr. Pugh's compensation is paid directly to Jackson Electric Membership Corporation, where he serves as President and Chief Executive Officer.

During 2011, we paid our member directors a fee of $1,200 per board meeting and $800 per day for attending committee meetings, other meetings, or other official business approved by the chairman of the board of directors. Member directors are paid $600 per day for attending the annual meeting of members and member advisory board meetings. Our outside director was paid a fee of $5,500 per board meeting for four meetings a year and a fee of $1,000 per board meeting for the remaining other board meetings held during the year. Our outside director was also paid $1,000 per day for attending committee meetings, annual meetings of the members or other official business. In addition, we reimburse all directors for out-of-pocket expenses incurred in attending a meeting. All directors are paid $100 per day when participating in meetings by conference call. The chairman of the board of directors is paid an additional 20% of his director's fee per board meeting for time involved in preparing for the meetings. The audit committee financial expert is paid an additional $400 per audit committee meeting for the time involved in fulfilling that role. Neither our outside director nor member directors receive any perquisites or other personal benefits from us.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

Jeffrey Murphy is a director of ours and the President and Chief Executive Officer of Hart Electric Membership Corporation. Hart is a member of ours and has a wholesale power contract with us. Hart's revenues of $21.1 million to us in 2011 under its wholesale power contract accounted for approximately 1.5% of our total revenues.

Hill Bentley is a director of ours and the Chief Executive Officer of Tri-County Electric Membership Corporation. Tri-County is a member of ours and has a wholesale power contract with us. Tri-County's revenues of $14.4 million to us in 2011 under its wholesale power contract accounted for approximately 1.0% of our total revenues.

Danny Nichols is a director of ours and is the General Manager of Colquitt Electric Membership Corporation. Prior to Mr. Nichols joining our board of directors in March of 2011, Rick Gaston was a director of ours through January 2011 and was the prior General Manager of Colquitt. Colquitt is a member of ours and has a wholesale power contract with us. Colquitt's revenues of $37.5 million to us in 2011 under its wholesale power contract accounted for approximately 2.7% of our total revenues.

Randall Pugh is a director of ours and the President and Chief Executive Officer of Jackson Electric Membership Corporation. Jackson is a member of ours and has a wholesale power contract with us. Jackson's revenues of $151.7 million to us in 2011 under its wholesale power contract accounted for approximately 10.9% of our total revenues.

George Weaver is a director of ours and the President of Central Georgia Electric Membership Corporation. Central Georgia is a member of ours and has a wholesale power contract with us. Central Georgia's revenues of $31.7 million to us in 2011 under its wholesale power contract accounted for approximately 2.3% of our total revenues.

We have a Standards of Conduct/Conflict of Interest policy that sets forth guidelines that our employees and directors must follow in order to avoid conflicts of interest, or any appearance of conflicts of interest, between an individual's personal interests and our interests. Pursuant to this policy, each employee and director must disclose any conflicts of interest, actions or relationships that might give rise to a conflict. Our president and chief executive officer is responsible for taking reasonable steps to ensure that the employees are complying with this policy and the audit committee is responsible for taking reasonable steps to ensure that the directors are complying with this policy. The audit committee is charged with monitoring compliance with this policy and making recommendations to the board of directors regarding this policy. Certain actions or relationships that might give rise to a conflict of interest are reviewed and approved by our board of directors.

Director Independence

Because we are an electric cooperative, the members own and manage us. Our bylaws set forth specific requirements regarding the composition of our board of directors. See "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE – Our Board of Directors – *Structure of Our Board of Directors*" for a detailed discussion of the specific requirements contained in our bylaws regarding the composition of our board of directors.

In addition to meeting the requirements set forth in our bylaws, all directors, with the exception of Randall Pugh, satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet the requirements set forth in our bylaws. Randall Pugh does not qualify as an independent director because he is the President and Chief Executive Officer of Jackson, which accounted for approximately 10.9% of our revenues for the fiscal year ended December 31, 2011. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria in making this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For 2011 and 2010, fees for services provided by our independent registered public accounting firm, Ernst & Young LLP were as follows:

	2011	2010
	(dollars in thousands)	
Audit Fees[(1)]	**$ 548**	$ 574
Audit-Related Fees[(2)]	**2**	24
Tax Fees[(3)]	**25**	–
Total	**$ 575**	$ 598

(1) Audit of annual financial statements and review of financial statements included in SEC filings and services rendered in connection with financings.

(2) Other audit-related services.

(3) Professional tax services including tax consultation and tax return compliance.

In considering the nature of the services provided by our independent registered public accounting firm, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed all non-audit services to be provided by independent registered public accounting firm to us with management prior to approving them to confirm that they were non-audit services permitted to be provided by our independent registered public accounting firm.

Pre-Approval Policy

The audit and permissible non-audit services performed by Ernst & Young LLP in 2011 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. The policy requires that requests for all services must be submitted to the audit committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of Documents Filed as a Part of This Report.

(2) Financial Statement Schedules

None applicable.

(3) Exhibits

Exhibits marked with an asterisk (*) are hereby incorporated by reference to exhibits previously filed by the Registrant as indicated in parentheses following the description of the exhibit.

Number		Description
*3.1(a)	–	Restated Articles of Incorporation of Oglethorpe, dated as of July 26, 1988. (Filed as Exhibit 3.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*3.1(b)	–	Amendment to Articles of Incorporation of Oglethorpe, dated as of March 11, 1997. (Filed as Exhibit 3(i)(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*3.2	–	Bylaws of Oglethorpe, as amended and restated, as of May 1, 2008 (Updated on May 1, 2010 to reflect SMG membership change). (Filed as Exhibit 3.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010, File No. 000-53908.)
*4.1	–	Amended and Restated Indenture of Trust, Deed to Secure Debt and Security Agreement No. 2, dated December 1, 1997, between Wilmington Trust Company and NationsBank, N.A. collectively as Owner Trustee, under Trust Agreement No. 2, dated December 30, 1985, with DFO Partnership, as assignee of Ford Motor Credit Company, and The Bank of New York Trust Company of Florida, N.A. as Indenture Trustee, with a Schedule identifying three other substantially identical Amended and Restated Indentures of Trust, Deeds to Secure Debt and Security Agreements and any material differences. (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*4.2(a)	–	Lease Agreement No. 2, dated December 30, 1985, between Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Lessor, and Oglethorpe, Lessee, with a Schedule identifying three other substantially identical Lease Agreements. (Filed as Exhibit 4.5(b) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)

*4.2(b)	–	First Supplement to Lease Agreement No. 2 (included as Exhibit B to the Supplemental Participation Agreement No. 2 listed as 10.1.1(b)).
*4.2(c)	–	First Supplement to Lease Agreement No. 1, dated as of June 30, 1987, between The Citizens and Southern National Bank as Owner Trustee under Trust Agreement No. 1 with IBM Credit Financing Corporation, as Lessor, and Oglethorpe, as Lessee. (Filed as Exhibit 4.5(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*4.2(d)	–	Second Supplement to Lease Agreement No. 2, dated as of December 17, 1997, between NationsBank, N.A., acting through its agent, The Bank of New York, as an Owner Trustee under the Trust Agreement No. 2, dated December 30, 1985, among DFO Partnership, as assignee of Ford Motor Credit Company, as the Owner Participant, and the Original Trustee, as Lessor, and Oglethorpe, as Lessee, with a Schedule identifying three other substantially identical Second Supplements to Lease Agreements and any material differences. (Filed as Exhibit 4.5(d) to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*4.3	–	Seventh Amended and Restated Loan Contract, dated as of April 15, 2011, between Oglethorpe and the United States of America, together with four notes executed and delivered pursuant thereto. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.4.1(a)	–	Indenture, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. (Filed as Exhibit 4.8.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.4.1(b)	–	First Supplemental Indenture, dated as of October 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1997B (Burke) Note. (Filed as Exhibit 4.8.1(b) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1997, File No. 33-7591.)
*4.4.1(c)	–	Second Supplemental Indenture, dated as of January 1, 1998, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1997C (Burke) Note. (Filed as Exhibit 4.7.1(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1997, File No. 33-7591.)
*4.4.1(d)	–	Third Supplemental Indenture, dated as of January 1, 1998, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1997A (Monroe) Note. (Filed as Exhibit 4.7.1(d) to the Registrant's Form 10-K for the fiscal year December 31, 1997, File No. 33-7591.)
*4.4.1(e)	–	Fourth Supplemental Indenture, dated as of March 1, 1998, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998A (Burke) and 1998B (Burke) Notes. (Filed as Exhibit 4.7.1(e) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.4.1(f)	–	Fifth Supplemental Indenture, dated as of April 1, 1998, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998 CFC Note. (Filed as Exhibit 4.7.1(f) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.4.1(g)	–	Sixth Supplemental Indenture, dated as of January 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998C (Burke) Note. (Filed as Exhibit 4.7.1(g) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.4.1(h)	–	Seventh Supplemental Indenture, dated as of January 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998A (Monroe) Note. (Filed as Exhibit 4.7.1(h) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)

*4.4.1(i)	–	Eighth Supplemental Indenture, dated as of November 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999B (Burke) Note. (Filed as Exhibit 4.7.1(i) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(j)	–	Ninth Supplemental Indenture, dated as of November 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999B (Monroe) Note. (Filed as Exhibit 4.7.1(j) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(k)	–	Tenth Supplemental Indenture, dated as of December 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999 Lease Notes. (Filed as Exhibit 4.7.1(k) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(l)	–	Eleventh Supplemental Indenture, dated as of January 1, 2000, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1999A (Burke) Note. (Filed as Exhibit 4.7.1(l) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(m)	–	Twelfth Supplemental Indenture, dated as of January 1, 2000, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1999A (Monroe) Note. (Filed as Exhibit 4.7.1(m) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(n)	–	Thirteenth Supplemental Indenture, dated as of January 1, 2001, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2000 (Burke) Note. (Filed as Exhibit 4.7.1(n) to the Registrant's Form 10-K for the fiscal year ended December 31, 2000, File No. 33-7591.)
*4.4.1(o)	–	Fourteenth Supplemental Indenture, dated as of January 1, 2001, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2000 (Monroe) Note. (Filed as Exhibit 4.7.1(o) to the Registrant's Form 10-K for the fiscal year ended December 31, 2000, File No. 33-7591.)
*4.4.1(p)	–	Fifteenth Supplemental Indenture, dated as of January 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2001 (Burke) Note. (Filed as Exhibit 4.7.1(p) to the Registrant's Form 10-K for the fiscal year ended December 31, 2001, File No. 33-7591.)
*4.4.1(q)	–	Sixteenth Supplemental Indenture, dated as of January 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2001 (Monroe) Note. (Filed as Exhibit 4.7.1(q) to the Registrant's Form 10-K for the fiscal year ended December 31, 2001, File No. 33-7591.)
*4.4.1(r)	–	Seventeenth Supplemental Indenture, dated as of October 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002A (Burke) Note. (Filed as Exhibit 4.7.1(r) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(s)	–	Eighteenth Supplemental Indenture, dated as of October 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002B (Burke) Note. (Filed as Exhibit 4.7.1(s) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(t)	–	Nineteenth Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002C (Burke) Note. (Filed as Exhibit 4.7.1(t) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)

*4.4.1(u)	–	Twentieth Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002 (Monroe) Note. (Filed as Exhibit 4.7.1(u) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(v)	–	Twenty-First Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002 (Appling) Note. (Filed as Exhibit 4.7.1(v) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(w)	–	Twenty-Second Supplemental Indenture, dated as of March 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003 (FFB M-8) Note and Series 2003 (RUS M-8) Reimbursement Note. (Filed as Exhibit 4.7.1(w) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003, File No. 33-7591.)
*4.4.1(x)	–	Twenty-Third Supplemental Indenture, dated as of March 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003 (FFB N-8) Note and Series 2003 (RUS N-8) Reimbursement Note. (Filed as Exhibit 4.7.1(x) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003, File No. 33-7591.)
*4.4.1(y)	–	Twenty-Fourth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Appling) Note. (Filed as Exhibit 4.7.1(y) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(z)	–	Twenty-Fifth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Burke) Note. (Filed as Exhibit 4.7.1(z) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(aa)	–	Twenty-Sixth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003B (Burke) Note. (Filed as Exhibit 4.7.1(aa) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(bb)	–	Twenty-Seventh Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Heard) Note. (Filed as Exhibit 4.7.1(bb) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(cc)	–	Twenty-Eighth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Monroe) Note. (Filed as Exhibit 4.7.1(cc) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(dd)	–	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2004, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2004 (Burke) Note. (Filed as Exhibit 4.7.1(dd) to the Registrant's Form 10-K for the fiscal year ended December 31, 2004, File No. 33-7591.)
*4.4.1(ee)	–	Thirtieth Supplemental Indenture, dated as of December 1, 2004, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2004 (Monroe) Note. (Filed as Exhibit 4.7.1(ee) to the Registrant's Form 10-K for the fiscal year ended December 31, 2004, File No. 33-7591.)
*4.4.1(ff)	–	Thirty-First Supplemental Indenture, dated as of November 1, 2005, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2005 (Burke) Note. (Filed as Exhibit 4.7.1(ff) to the Registrant's Form 10-K for the fiscal year ended December 31, 2005, File No. 33-7591.)

*4.4.1(gg)	–	Thirty-Second Supplemental Indenture, dated as of November 1, 2005, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2005 (Monroe) Note. (Filed as Exhibit 4.7.1(gg) to the Registrant's Form 10-K for the fiscal year ended December 31, 2005, File No. 33-7591.)
*4.4.1(hh)	–	Thirty-Third Supplemental Indenture, dated as of May 1, 2006, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2006 (FFB P-8) Note and Series 2006 (RUS P-8) Reimbursement Note. (Filed as Exhibit 4.7.1(hh) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006, File No. 33-7591.)
*4.4.1(ii)	–	Thirty-Fourth Supplemental Indenture, dated as of September 22, 2006, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Amendment of Section 9.9 of the Original Indenture. (Filed as Exhibit 4.7.1(ii) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(jj)	–	Thirty-Fifth Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2006. (Filed as Exhibit 4.7.1(jj) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(kk)	–	Thirty-Sixth Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2006A (Burke) Note, Series 2006B-1 (Burke) Note, Series 2006B-2 (Burke) Note, Series 2006B-3 (Burke) Note, Series 2006B-4 (Burke) Note and Series 2006A (Monroe) Note. (Filed as Exhibit 4.7.1(kk) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(ll)	–	Thirty-Seventh Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2006C-1 (Burke) Note, Series 2006C-2 (Burke) Note and Series 2006B (Monroe) Note. (Filed as Exhibit 4.7.1(ll) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(mm)	–	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Amendments to the Retained Indebtedness Note. (Filed as Exhibit 4.7.1(mm) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2007, File No. 33-7591.)
*4.4.1(nn)	–	Thirty-Ninth Supplemental Indenture, dated as of July 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2007 (FFB R-8) Note and Series 2007 (RUS R-8) Reimbursement Note. (Filed as Exhibit 4.7.1(nn) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2007, File No. 33-7591.)
*4.4.1(oo)	–	Fortieth Supplemental Indenture, dated as of October 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2007. (Filed as Exhibit 4.7.1(oo) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2007, File No. 33-7591.)
*4.4.1(pp)	–	Forty-First Supplemental Indenture, dated as of October 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2007A (Appling) Note, Series 2007B (Appling) Note, Series 2007A (Burke) Note, Series 2007B (Burke) Note, Series 2007C (Burke) Note, Series 2007D (Burke) Note, Series 2007E (Burke) Note, Series 2007F (Burke) Note and Series 2007A (Monroe) Note. (Filed as Exhibit 4.7.1(pp) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2007, File No. 33-7591.)

*4.4.1(qq)	–	Forty-Second Supplemental Indenture, dated as of February 5, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, providing for the Amendment of Section 1.1 of the Original Indenture. (Filed as Exhibit 4.7(qq) to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.)
*4.4.1(rr)	–	Forty-Third Supplemental Indenture, dated as of August 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008A (Burke) Note, Series 2008B (Burke) Note and Series 2008C (Burke) Note. (Filed as Exhibit 4.7.1(rr) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(ss)	–	Forty-Fourth Supplemental Indenture, dated as of September 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008 (FFB S-8) Note and Series 2008 (RUS S-8) Reimbursement Note. (Filed as Exhibit 4.7.1(ss) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(tt)	–	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008D (Burke) Note, Series 2008E (Burke) Note, Series 2008F (Burke) Note, Series 2008G (Burke) Note and Series 2008A (Monroe) Note. (Filed as Exhibit 4.7.1(tt) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(uu)	–	Forty-Sixth Supplemental Indenture, dated as of February 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2009 A. (Filed as Exhibit 4.7.1(uu) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(vv)	–	Forty-Seventh Supplemental Indenture, dated as of February 19, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, providing for the Amendment of the Original Indenture. (Filed as Exhibit 4.7.1(vv) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(ww)	–	Forty-Eighth Supplemental Indenture, dated as of August 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009B CFC Note, Series 2009C CFC Note and Series 2009D CFC Project Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2009, File No. 333-159338.)
*4.4.1(xx)	–	Forty-Ninth Supplemental Indenture, dated as of November 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2009 B. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarter ended September 30, 2009, File No. 333-159338.)
*4.4.1(yy)	–	Fiftieth Supplemental Indenture, dated as of November 30, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009A Line of Credit Notes. (Filed as Exhibit 4.7.1 (yy) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*4.4.1 (zz)	–	Fifty-First Supplemental Indenture, dated as of December 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009A (Heard) Note, Series 2009A (Monroe) Note and Series 2009B (Monroe) Note. (Filed as Exhibit 4.7.1 (zz) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)

*4.4.1 (aaa)	–	Fifty-Second Supplemental Indenture, dated as of December 30, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond). (Filed as Exhibit 4.7.1 (aaa) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*4.4.1 (bbb)	–	Fifty-Third Supplemental Indenture, dated as of March 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010A (Burke) Note, Series 2010B (Burke) Note, Series 2010A (Monroe) Note, Series 2010A (Burke) Reimbursement Obligation, Series 2010B (Burke) Reimbursement Obligation and Series 2010A (Monroe) Reimbursement Obligation. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010, File No. 000-53908.)
*4.4.1 (ccc)	–	Fifty-Fourth Supplemental Indenture, dated as of May 21, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, confirming the lien of the Indenture with respect to certain After-Acquired Property (relating to the Hawk Road and Hartwell Energy Facilities). (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2010, File No. 000-53908.)
*4.4.1 (ddd)	–	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010 (FFB V-8) Note and Series 2010 (RUS V-8) Reimbursement Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2010, File No. 000-53908.)
*4.4.1 (eee)	–	Fifty-Sixth Supplemental Indenture, dated as of November 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2010 A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 8, 2010, File No. 000-53908.)
*4.4.1(fff)	–	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010A CFC Note. (Filed as Exhibit 4.8.1(fff) to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
*4.4.1(ggg)	–	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Agreement Modifying Future Advance Promissory Note. (Filed as Exhibit 4.8.1(ggg) to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
*4.4.1(hhh)	–	Fifty-Ninth Supplemental Indenture, dated as of March 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2011A (Appling) Note, Series 2011A (Burke) Note and Series 2011A (Monroe) Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.4.1(iii)	–	Sixtieth Supplemental Indenture, dated as of April 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2011 (FFB W-8) Note, Series 2011 (RUS W-8) Reimbursement Note, Series 2011 (FFB X-8) Note, and Series 2011 (RUS X-8) Reimbursement Note. (Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.4.1(jjj)	–	Sixty-First Supplemental Indenture, dated as of August 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2011A (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2011, File No. 000-53908.)

*4.4.2	–	Security Agreement, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. (Filed as Exhibit 4.8.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.5	–	Unsecured Indenture, dated as of December 22, 2010, by and between Oglethorpe and U.S. Bank National Association, as trustee (Filed as Exhibit 4.1 to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
4.6.1[(1)]	–	Loan Agreement, dated as of October 1, 1992, between Development Authority of Monroe County and Oglethorpe relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 1992A, and four other substantially identical (Fixed Rate Bonds) loan agreements.
4.6.2[(1)]	–	Note, dated October 1, 1992, from Oglethorpe to Trust Company Bank, as trustee, acting pursuant to a Trust Indenture, dated as of October 1, 1992, between Development Authority of Monroe County and Trust Company Bank relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 1992A, and four other substantially identical notes.
4.6.3[(1)]	–	Trust Indenture, dated as of October 1, 1992, between Development Authority of Monroe County and Trust Company Bank, Trustee, relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 1992A, and four other substantially identical indentures.
4.7.1[(1)]	–	Loan Agreement, dated as of December 1, 2003, between Development Authority of Burke County and Oglethorpe relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2003A, and seven other substantially identical (Auction Rate Bonds) loan agreements.
4.7.2[(1)]	–	Note, dated December 3, 2003, from Oglethorpe to SunTrust Bank, as trustee, pursuant to a Trust Indenture, dated December 1, 2003, between Development Authority of Burke County and SunTrust Bank relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2003A, and seven other substantially identical notes.
4.7.3[(1)]	–	Trust Indenture, dated as of December 1, 2003, between Development Authority of Burke County and SunTrust Bank, as trustee, relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2003A, and seven other substantially identical indentures.
4.8.1[(1)]	–	Loan Agreement, dated as of March 1, 2011, between Development Authority of Monroe County and Oglethorpe relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2011A, and three other substantially identical (Term Rate Bonds) loan agreements.
4.8.2[(1)]	–	Note, dated as of March 31, 2011, from Oglethorpe to U.S. Bank National Association, as trustee, pursuant to a Trust Indenture, dated as of March 1, 2011, between the Development Authority of Monroe County and U.S. Bank National Association relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2011A, and three other substantially identical notes.

4.8.3[1]	–	Trust Indenture, dated as March 1, 2011, between Development Authority of Monroe County and U.S. Bank National Association, as trustee, relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2011A, and three other substantially identical indentures.
4.9.1[1]	–	Loan Agreement, dated as of December 1, 2009, between Development of Monroe County and Oglethorpe relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical (Variable Rate Bonds) loan agreements.
4.9.2[1]	–	Note, dated December 1, 2009, from Oglethorpe to U.S. Bank National Association , as trustee, pursuant to a Trust Indenture, dated December 1, 2009, between Development Authority of Monroe County and U.S. Bank National Association relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical notes.
4.9.3[1]	–	Trust Indenture, dated December 1, 2009, between Development Authority of Monroe County and U.S. Bank National Association, as trustee, relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical indentures.
*4.10.1	–	Indemnity Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia Transmission Corporation (An Electric Membership Corporation). (Filed as Exhibit 4.13.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.10.2	–	Indemnification Agreement, dated as of March 11, 1997, by Oglethorpe and Georgia Transmission Corporation (An Electric Membership Corporation) for the benefit of the United States of America. (Filed as Exhibit 4.13.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
4.11.1[1]	–	Master Loan Agreement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, MLA No. 0459.
4.11.2[1]	–	Consolidating Supplement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, relating to Loan No. ML0459T1.
4.11.3[1]	–	Promissory Note, dated March 1, 1997, in the original principal amount of $7,102,740.26, from Oglethorpe to CoBank, ACB, relating to Loan No. ML0459T1.
4.11.4[1]	–	Consolidating Supplement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, relating to Loan No. ML0459T2.
4.11.5[1]	–	Promissory Note, dated March 1, 1997, in the original principal amount of $1,856,475.12, made by Oglethorpe to CoBank, ACB, relating to Loan No. ML0459T2.
4.12.1[1]	–	Committed, Revolving Credit Facility Agreement, dated as of August 1, 2009, between Oglethorpe and National Rural Utilities Cooperative Finance Corporation, relating to the Series 2009B CFC Note.
4.12.2[1]	–	Series 2009B CFC Note, dated August 11, 2009, in the original principal amount of $250,000,000, from Oglethorpe to National Rural Utilities Cooperative Finance Corporation.
4.12.3[1]	–	Term Loan Agreement, dated as of August 1, 2009, between Oglethorpe and National Rural Utilities Cooperative Finance Corporation, relating to the Series 2009C Note.
4.12.4[1]	–	Series 2009C CFC Note, dated August 11, 2009, in the original principal amount of $250,000,000, from Oglethorpe to National Rural Utilities Cooperative Finance Corporation.

4.13.1[1]	–	Credit Agreement, dated as of November 30, 2009, between Oglethorpe and CoBank, ACB, relating to the Series 2009A CoBank Note.
4.13.2[1]	–	Series 2009A CoBank Note, dated November 30, 2009, in the original principal amount of $150,000,000, made by Oglethorpe to CoBank, ACB.
4.14.1[1]	–	Bond Purchase Agreement, dated as of December 30, 2009, between Oglethorpe and CoBank, ACB, relating to Oglethorpe Power Corporation (An Electric Membership Corporation) First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond).
4.14.2[1]	–	Oglethorpe Power Corporation (An Electric Membership Corporation) First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond), dated December 30, 2009, from Oglethorpe to CoBank, ACB, in the original principal amount of $16,165,400.
*10.1.1(a)	–	Participation Agreement No. 2 among Oglethorpe as Lessee, Wilmington Trust Company as Owner Trustee, The First National Bank of Atlanta as Indenture Trustee, Columbia Bank for Cooperatives as Loan Participant and Ford Motor Credit Company as Owner Participant, dated December 30, 1985, together with a Schedule identifying three other substantially identical Participation Agreements. (Filed as Exhibit 10.1.1(b) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.1(b)	–	Supplemental Participation Agreement No. 2. (Filed as Exhibit 10.1.1(a) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.1(c)	–	Supplemental Participation Agreement No. 1, dated as of June 30, 1987, among Oglethorpe as Lessee, IBM Credit Financing Corporation as Owner Participant, Wilmington Trust Company and The Citizens and Southern National Bank as Owner Trustee, The First National Bank of Atlanta, as Indenture Trustee, and Columbia Bank for Cooperatives, as Loan Participant. (Filed as Exhibit 10.1.1(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.1(d)	–	Second Supplemental Participation Agreement No. 2, dated as of December 17, 1997, among Oglethorpe as Lessee, DFO Partnership, as assignee of Ford Motor Credit Company, as Owner Participant, Wilmington Trust Company and NationsBank, N.A. as Owner Trustee, The Bank of New York Trust Company of Florida, N.A. as Indenture Trustee, CoBank, ACB as Loan Participant, OPC Scherer Funding Corporation, as Original Funding Corporation, OPC Scherer 1997 Funding Corporation A, as Funding Corporation, and SunTrust Bank, Atlanta, as Original Collateral Trust Trustee and Collateral Trust Trustee, with a Schedule identifying three substantially identical Second Supplemental Participation Agreements and any material differences. (Filed as Exhibit 10.1.1(d) to Registrant's Form S-4 Registration Statement, File No. 333-4275.)
*10.1.2	–	General Warranty Deed and Bill of Sale No. 2 between Oglethorpe, Grantor, and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Grantee, together with a Schedule identifying three substantially identical General Warranty Deeds and Bills of Sale. (Filed as Exhibit 10.1.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.3(a)	–	Supporting Assets Lease No. 2, dated December 30, 1985, between Oglethorpe, Lessor, and Wilmington Trust Company and William J. Wade, as Owner Trustees, under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Lessee, together with a Schedule identifying three substantially identical Supporting Assets Leases. (Filed as Exhibit 10.1.3 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)

*10.1.3(b)	–	First Amendment to Supporting Assets Lease No. 2, dated as of November 19, 1987, together with a Schedule identifying three substantially identical First Amendments to Supporting Assets Leases. (Filed as Exhibit 10.1.3(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.3(c)	–	Second Amendment to Supporting Assets Lease No. 2, dated as of October 3, 1989, together with a Schedule identifying three substantially identical Second Amendments to Supporting Assets Leases. (Filed as Exhibit 10.1.3(c) to the Registrant's Form 10-Q for the quarterly period ended March 31, 1998, File No. 33-7591.)
*10.1.4(a)	–	Supporting Assets Sublease No. 2, dated December 30, 1985, between Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Sublessor, and Oglethorpe, Sublessee, together with a Schedule identifying three substantially identical Supporting Assets Subleases. (Filed as Exhibit 10.1.4 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.4(b)	–	First Amendment to Supporting Assets Sublease No. 2, dated as of November 19, 1987, together with a Schedule identifying three substantially identical First Amendments to Supporting Assets Subleases. (Filed as Exhibit 10.1.4(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.1.4(c)	–	Second Amendment to Supporting Assets Sublease No. 2, dated as of October 3, 1989, together with a Schedule identifying three substantially identical Second Amendments to Supporting Assets Subleases. (Filed as Exhibit 10.1.4(c) to the Registrant's Form 10-Q for the quarterly period ended March 31, 1998, File No. 33-7591.)
*10.1.5(a)	–	Tax Indemnification Agreement No. 2, dated December 30, 1985, between Ford Motor Credit Company, Owner Participant, and Oglethorpe, Lessee, together with a Schedule identifying three substantially identical Tax Indemnification Agreements. (Filed as Exhibit 10.1.5 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.5(b)	–	Amendment No. 1 to the Tax Indemnification Agreement No. 2, dated December 17, 1997, between DFO Partnership, as assignee of Ford Motor Credit Company, as Owner Participant, and Oglethorpe, as Lessee, with a Schedule identifying three substantially identical Amendments No. 1 to the Tax Indemnification Agreements and any material differences. (Filed as Exhibit 10.1.5(b) to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*10.1.6	–	Assignment of Interest in Ownership Agreement and Operating Agreement No. 2, dated December 30, 1985, between Oglethorpe, Assignor, and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Assignee, together with Schedule identifying three substantially identical Assignments of Interest in Ownership Agreement and Operating Agreement. (Filed as Exhibit 10.1.6 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.1.7(a)	–	Consent, Amendment and Assumption No. 2, dated December 30, 1985, among Georgia Power Company and Oglethorpe and Municipal Electric Authority of Georgia and City of Dalton, Georgia and Gulf Power Company and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, together with a Schedule identifying three substantially identical Consents, Amendments and Assumptions. (Filed as Exhibit 10.1.9 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)

*10.1.7(b)	–	Amendment to Consent, Amendment and Assumption No. 2, dated as of August 16, 1993, among Oglethorpe, Georgia Power Company, Municipal Electric Authority of Georgia, City of Dalton, Georgia, Gulf Power Company, Jacksonville Electric Authority, Florida Power & Light Company and Wilmington Trust Company and NationsBank of Georgia, N.A., as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, together with a Schedule identifying three substantially identical Amendments to Consents, Amendments and Assumptions. (Filed as Exhibit 10.1.9(a) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.2.1	–	Section 168 Agreement and Election, dated as of April 7, 1982, between Continental Telephone Corporation and Oglethorpe. (Filed as Exhibit 10.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.2.2	–	Section 168 Agreement and Election, dated as of April 9, 1982, between Rollins, Inc. and Oglethorpe. (Filed as Exhibit 10.4 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.3.1(a)	–	Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of May 15, 1980. (Filed as Exhibit 10.6.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.3.1(b)	–	Amendment to Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 30, 1985. (Filed as Exhibit 10.1.8 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.3.1(c)	–	Amendment Number Two to the Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of July 1, 1986. (Filed as Exhibit 10.6.1(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*10.3.1(d)	–	Amendment Number Three to the Plant Robert W. Scherer Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of August 1, 1988. (Filed as Exhibit 10.6.1(b) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.3.1(e)	–	Amendment Number Four to the Plant Robert W. Scherer Units Number One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 31, 1990. (Filed as Exhibit 10.6.1(c) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.3.2(a)	–	Plant Robert W. Scherer Units Numbers One and Two Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of May 15, 1980. (Filed as Exhibit 10.6.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.3.2(b)	–	Amendment to Plant Robert W. Scherer Units Numbers One and Two Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 30, 1985. (Filed as Exhibit 10.1.7 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)

*10.3.2(c)	–	Amendment Number Two to the Plant Robert W. Scherer Units Numbers One and Two Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of December 31, 1990. (Filed as Exhibit 10.6.2(a) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.3.3	–	Plant Scherer Managing Board Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, City of Dalton, Georgia, Gulf Power Company, Florida Power & Light Company and Jacksonville Electric Authority, dated as of December 31, 1990. (Filed as Exhibit 10.6.3 to the Registrant's Form 10-Q for the quarterly period ended September 30, 1993, File No. 33-7591.)
*10.4.1(a)	–	Alvin W. Vogtle Nuclear Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of August 27, 1976. (Filed as Exhibit 10.7.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.4.1(b)	–	Amendment Number One, dated January 18, 1977, to the Alvin W. Vogtle Nuclear Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.7.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1986, File No. 33-7591.)
*10.4.1(c)	–	Amendment Number Two, dated February 24, 1977, to the Alvin W. Vogtle Nuclear Units Numbers One and Two Purchase and Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.7.4 to the Registrant's Form 10-K for the fiscal year ended December 31, 1986, File No. 33-7591.)
*10.4.2	–	Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of April 21, 2006. (Filed as Exhibit 10.4.4 to the Registrant's Form 8-K, filed April 27, 2006, File No. 33-7591.)
*10.4.3	–	Plant Alvin W. Vogtle Nuclear Units Amended and Restated Operating Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of April 21, 2006. (Filed as Exhibit 10.4.3 to the Registrant's Form 8-K, filed April 27, 2006, File No. 33-7591.)
10.4.4(2)	–	Engineering, Procurement and Construction Agreement between Georgia Power Company, acting for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, as owners and a consortium consisting of Westinghouse Electric Company LLC and Stone & Weber, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, dated as of April 8, 2008. (Incorporated by reference to Exhibit 10(c)1 of Georgia Power Company's Form 10-Q/A for the quarterly period ended June 30, 2008, filed with the SEC on January 26, 2009.)
10.4.5(2)	–	Amendment No. 1, dated as of December 11, 2009, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)29 of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2009, filed with the SEC on February 25, 2010.)

10.4.6(2)	–	Amendment No. 2, dated as of January 15, 2010, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(1) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2010, filed with the SEC on May 7, 2010.)
10.4.7(2)	–	Amendment No. 3, dated as of February 23, 2010, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2010, filed with the SEC on May 7, 2010.)
*10.5.1	–	Plant Hal Wansley Purchase and Ownership Participation Agreement between Georgia Power Company and Oglethorpe, dated as of March 26, 1976. (Filed as Exhibit 10.8.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.5.2(a)	–	Plant Hal Wansley Operating Agreement between Georgia Power Company and Oglethorpe, dated as of March 26, 1976. (Filed as Exhibit 10.8.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.5.2(b)	–	Amendment, dated as of January 15, 1995, to the Plant Hal Wansley Operating Agreements by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (Filed as Exhibit 10.5.2(a) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1996, File No. 33-7591.)
*10.5.3	–	Plant Hal Wansley Combustion Turbine Agreement between Georgia Power Company and Oglethorpe, dated as of August 2, 1982 and Amendment No. 1, dated October 20, 1982. (Filed as Exhibit 10.18 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.6.1	–	Edwin I. Hatch Nuclear Plant Purchase and Ownership Participation Agreement between Georgia Power Company and Oglethorpe, dated as of January 6, 1975. (Filed as Exhibit 10.9.1 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.6.2	–	Edwin I. Hatch Nuclear Plant Operating Agreement between Georgia Power Company and Oglethorpe, dated as of January 6, 1975. (Filed as Exhibit 10.9.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*10.7.1	–	Rocky Mountain Pumped Storage Hydroelectric Project Ownership Participation Agreement, dated as of November 18, 1988, by and between Oglethorpe and Georgia Power Company. (Filed as Exhibit 10.22.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*10.7.2	–	Rocky Mountain Pumped Storage Hydroelectric Project Operating Agreement, dated as of November 18, 1988, by and between Oglethorpe and Georgia Power Company. (Filed as Exhibit 10.22.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*10.8.1	–	Amended and Restated Wholesale Power Contract, dated as of January 1, 2003, between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 38 other substantially identical Amended and Restated Wholesale Power Contracts. (Filed as Exhibit 10.31.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003, File No. 33-7591.)

*10.8.2	–	First Amendment to Amended and Restated Wholesale Power Contract, dated as of June 1, 2005, between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 37 other substantially identical First Amendments. (Filed as Exhibit 10.8.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2005, File No. 33-7591.)
*10.8.3	–	Amended and Restated Supplemental Agreement, dated as of January 1, 2003, by and among Oglethorpe, Altamaha Electric Membership Corporation and the United States of America, together with a schedule identifying 38 other substantially identical Amended and Restated Supplemental Agreements. (Filed as Exhibit 10.31.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003, File No. 33-7591.)
*10.8.4	–	Supplemental Agreement to the Amended and Restated Wholesale Power Contract, dated as of January 1, 1997, by and among Georgia Power Company, Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 38 other substantially identical Supplemental Agreements. (Filed as Exhibit 10.8.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.8.5	–	Supplemental Agreement to the Amended and Restated Wholesale Power Contract, dated as of March 1, 1997, by and between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 36 other substantially identical Supplemental Agreements, and an additional Supplemental Agreement that is not substantially identical. (Filed as Exhibit 10.8.4 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.8.6	–	Supplemental Agreement to the Amended and Restated Wholesale Power Contract, dated as of March 1, 1997, by and between Oglethorpe and Coweta-Fayette Electric Membership Corporation, together with a schedule identifying 1 other substantially identical Supplemental Agreement. (Filed as Exhibit 10.8.5 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.8.7	–	Supplemental Agreement to the Amended and Restated Wholesale Power Contract, dated as of May 1, 1997 by and between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 38 other substantially identical Supplemental Agreements. (Filed as Exhibit 10.8.6 to the Registrant's Form 10-Q for the quarterly period ended June 30, 1997, File No. 33-7591.)
*10.8.8	–	Wholesale Power Contract, dated November 1, 2009, between Oglethorpe and Flint Electric Membership Corporation. (Filed as Exhibit 10.8.8 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*10.8.9	–	Supplemental Agreement to the Wholesale Power Contract, dated as of November 1, 2009, by and between Oglethorpe, Flint Electric Membership Corporation and the United States of America. (Filed as Exhibit 10.8.9 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*10.9	–	Letter of Commitment (Firm Power Sale) Under Service Schedule J – Negotiated Interchange Service between Alabama Electric Cooperative, Inc. and Oglethorpe, dated March 31, 1994. (Filed as Exhibit 10.11(b) to the Registrant's Form 10-Q for the quarter ended June 30, 1994, File No. 33-7591.)
*10.10	–	ITSA, Power Sale and Coordination Umbrella Agreement between Oglethorpe and Georgia Power Company, dated as of November 12, 1990. (Filed as Exhibit 10.28 to the Registrant's Form 8-K, filed January 4, 1991, File No. 33-7591.)

*10.11	–	Second Amended and Restated Nuclear Managing Board Agreement among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of April 21, 2006. (Filed as Exhibit 10.13(b) to the Registrant's Form 8-K, filed April 27, 2006, File No. 33-7591.)
*10.12	–	Supplemental Agreement by and among Oglethorpe, Tri-County Electric Membership Corporation and Georgia Power Company, dated as of November 12, 1990, together with a Schedule identifying 38 other substantially identical Supplemental Agreements. (Filed as Exhibit 10.30 to the Registrant's Form 8-K, filed January 4, 1991, File No. 33-7591.)
*10.13.1	–	Participation Agreement (P1), dated as of December 30, 1996, among Oglethorpe, Rocky Mountain Leasing Corporation, Fleet National Bank, as Owner Trustee, SunTrust Bank, Atlanta, as Co-Trustee, the Owner Participant named therein and Utrecht-America Finance Co., as Lender, together with a Schedule identifying five other substantially identical Participation Agreements. (Filed as Exhibit 10.32.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.1(a)	–	Amendment No. 1, dated as of June 1, 2003 to Participation Agreement (P1), dated as of December 30, 1996, among Oglethorpe, Rocky Mountain Leasing Corporation, U.S. Bank National Association, as Owner Trustee, SunTrust Bank, as Co-Trustee, the Owner Participant named therein and Utrecht-America Finance Co., as Lender, together with a Schedule identifying five other substantially identical Amendments No. 1 to the Participation Agreements. (Filed as Exhibit 10.16.1(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*10.13.1(b)(1)	–	Amendment No. 2 to Participation Agreement (P1), dated as of May 22, 2009, by and among Oglethorpe, Rocky Mountain Leasing Corporation, U.S. Bank National Association, as Owner Trustee, U.S. Bank National Association, as Co-Trustee, the Owner Participant named therein and Utrecht-America Finance Co., as Lender, together with a Schedule identifying four other substantially identical Amendments No. 2 to Participation Agreement. (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.1(b)(2)	–	Amendment No. 2 to Participation Agreement (N5), dated as of August 19, 2009, by and among Oglethorpe, Rocky Mountain Leasing Corporation, U.S. Bank National Association, as Owner Trustee, U.S. Bank National Association, as Co-Trustee, NationsBanc Leasing & R.E. Corporation, as Owner Participant, and Utrecht-America Finance Co., as Lender (Referenced as Exhibit 10.1 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)
*10.13.2	–	Rocky Mountain Head Lease Agreement (P1), dated as of December 30, 1996, between Oglethorpe and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Rocky Mountain Head Lease Agreements. (Filed as Exhibit 10.32.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.2(a)(1)	–	Amendment No. 1 to Head Lease Agreement (P1), dated as of May 22, 2009, by and between Oglethorpe and U.S. Bank National Association, as Co-Trustee, together with a Schedule identifying four other substantially identical Amendments No. 1 to Head Lease Agreement. (Filed as Exhibit 10.4 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.2(a)(2)	–	Amendment No. 1 to Head Lease Agreement (N5), dated as of August 19, 2009, by and between Oglethorpe and U.S. Bank National Association, as Co-Trustee. (Referenced as Exhibit 10.4 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)

*10.13.3	–	Ground Lease Agreement (P1), dated as of December 30, 1996, between Oglethorpe and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Ground Lease Agreements. (Filed as Exhibit 10.32.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.4	–	Rocky Mountain Agreements Assignment and Assumption Agreement (P1), dated as of December 30, 1996, between Oglethorpe and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Rocky Mountain Agreements Assignment and Assumption Agreements. (Filed as Exhibit 10.32.4 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.5	–	Facility Lease Agreement (P1), dated as of December 30, 1996, between SunTrust Bank, Atlanta, as Co-Trustee and Rocky Mountain Leasing Corporation, together with a Schedule identifying five other substantially identical Facility Lease Agreements. (Filed as Exhibit 10.32.5 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.5(a)(1)	–	Amendment No. 1 to Facility Lease Agreement (P1), dated as of May 22, 2009, by and between U.S. Bank National Association, as Co-Trustee, and Rocky Mountain Leasing Corporation, together with a Schedule identifying four other substantially identical Amendments No. 1 to Facility Lease Agreement. (Filed as Exhibit 10.5 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.5(a)(2)	–	Amendment No. 1 to Facility Lease Agreement (N5), dated as of August 19, 2009, by and between U.S. Bank National Association, as Co-Trustee, and Rocky Mountain Leasing Corporation. (Referenced as Exhibit 10.5 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)
*10.13.6	–	Ground Sublease Agreement (P1), dated as of December 30, 1996, between SunTrust Bank, Atlanta, as Co-Trustee and Rocky Mountain Leasing Corporation, together with a Schedule identifying five other substantially identical Ground Sublease Agreements. (Filed as Exhibit 10.32.6 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.7	–	Rocky Mountain Agreements Re-assignment and Assumption Agreement (P1), dated as of December 30, 1996, between SunTrust Bank, Atlanta, as Co-Trustee and Rocky Mountain Leasing Corporation, together with a Schedule identifying five other substantially identical Rocky Mountain Agreements Re-assignment and Assumption Agreements. (Filed as Exhibit 10.32.7 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.8	–	Facility Sublease Agreement (P1), dated as of December 30, 1996, between Oglethorpe and Rocky Mountain Leasing Corporation, together with a Schedule identifying five other substantially identical Facility Sublease Agreements. (Filed as Exhibit 10.32.8 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.8(a)(1)	–	Amendment No. 1 to Facility Sublease Agreement (P1), dated as of May 22, 2009, by and between Oglethorpe and Rocky Mountain Leasing Corporation, together with a Schedule identifying four other substantially identical Amendments No. 1 to Facility Sublease Agreement. (Filed as Exhibit 10.6 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.8(a)(2)	–	Amendment No. 1 to Facility Sublease Agreement (N5), dated as of August 19, 2009, by and between Oglethorpe and Rocky Mountain Leasing Corporation. (Referenced as Exhibit 10.6 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)

*10.13.9	–	Ground Sub-sublease Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation and Oglethorpe, together with a Schedule identifying five other substantially identical Ground Sub-sublease Agreements. (Filed as Exhibit 10.32.9 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.10	–	Rocky Mountain Agreements Second Re-assignment and Assumption Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation and Oglethorpe, together with a Schedule identifying five other substantially identical Rocky Mountain Agreements Second Re-assignment and Assumption Agreements. (Filed as Exhibit 10.32.10 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.11	–	Payment Undertaking Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation and Coöperatieve Centrale Raiffeisen-Boerenleenbank B.A., New York Branch, as the Bank, together with a Schedule identifying five other substantially identical Payment Undertaking Agreements. (Filed as Exhibit 10.32.11 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.12	–	Payment Undertaking Pledge Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation, Fleet National Bank, as Owner Trustee, and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Payment Undertaking Pledge Agreements. (Filed as Exhibit 10.32.12 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.13	–	Equity Funding Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation, AIG Match Funding Corp., the Owner Participant named therein, Fleet National Bank, as Owner Trustee, and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Equity Funding Agreements. (Filed as Exhibit 10.32.13 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.14	–	Equity Funding Pledge Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Equity Funding Pledge Agreements. (Filed as Exhibit 10.32.14 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.15	–	Deed to Secure Debt, Assignment of Surety Bond and Security Agreement (P1), dated as of December 30, 1996, between Rocky Mountain Leasing Corporation, SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Collateral Assignment, Assignment of Surety Bond and Security Agreements. (Filed as Exhibit 10.32.15 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.15(a)(1)	–	Amendment No. 1 to Deed to Secure Debt, Assignment of Surety Bond and Security Agreement (P1), dated as of May 22, 2009, by and between Rocky Mountain Leasing Corporation and U.S. Bank National Association, as Co-Trustee, together with a Schedule identifying four other substantially identical Amendments No.1 to Deed to Secure Debt, Assignment of Surety Bond and Security Agreement. (Filed as Exhibit 10.2 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)

*10.13.15(a)(2)	–	Amendment No. 1 to Deed to Secure Debt, Assignment of Surety Bond and Security Agreement (N5), dated as of August 19, 2009, by and between Rocky Mountain Leasing Corporation and U.S. Bank National Association, as Co-Trustee. (Referenced as Exhibit 10.2 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)
*10.13.16	–	Subordinated Deed to Secure Debt and Security Agreement (P1), dated as of December 30, 1996, among Oglethorpe, AMBAC Indemnity Corporation and SunTrust Bank, Atlanta, as Co-Trustee, together with a Schedule identifying five other substantially identical Subordinated Deed to Secure Debt and Security Agreements. (Filed as Exhibit 10.32.16 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.16(a)(1)	–	Amendment No. 1 to Subordinated Deed to Secure Debt and Security Agreement (P1), dated as of May 22, 2009, by and among Oglethorpe, U.S. Bank National Association, as Co-Trustee, and Ambac Assurance Corporation, together with a Schedule identifying four other substantially identical Amendments No. 1 to Subordinated Deed to Secure Debt and Security Agreement. (Filed as Exhibit 10.3 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.16(a)(2)	–	Amendment No. 1 to Subordinated Deed to Secure Debt and Security Agreement (N5), dated as of August 19, 2009, by and among Oglethorpe, U.S. Bank National Association, as Co-Trustee, and Ambac Assurance Corporation. (Referenced as Exhibit 10.3 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)
*10.13.17	–	Tax Indemnification Agreement (P1), dated as of December 30, 1996, between Oglethorpe and the Owner Participant named therein, together with a Schedule identifying five other substantially identical Tax Indemnification Agreements. (Filed as Exhibit 10.32.17 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.18	–	Consent No. 1, dated as of December 30, 1996, among Georgia Power Company, Oglethorpe, SunTrust Bank, Atlanta, as Co-Trustee, and Fleet National Bank, as Owner Trustee, together with a Schedule identifying five other substantially identical Consents. (Filed as Exhibit 10.32.18 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.19(a)	–	OPC Intercreditor and Security Agreement No. 1, dated as of December 30, 1996, among the United States of America, acting through the Administrator of the Rural Utilities Service, SunTrust Bank, Atlanta, Oglethorpe, Rocky Mountain Leasing Corporation, SunTrust Bank, Atlanta, as Co-Trustee, Fleet National Bank, as Owner Trustee, Utrecht-America Finance Co., as Lender and AMBAC Indemnity Corporation, together with a Schedule identifying five other substantially identical Intercreditor and Security Agreements. (Filed as Exhibit 10.32.19 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.13.19(b)	–	Supplement to OPC Intercreditor and Security Agreement No. 1, dated as of March 1, 1997, among the United States of America, acting through the Administrator of the Rural Utilities Service, SunTrust Bank, Atlanta, Oglethorpe, Rocky Mountain Leasing Corporation, SunTrust Bank, Atlanta, as Co-Trustee, Fleet National Bank, as Owner Trustee, Utrecht-America Finance Co., as Lender and AMBAC Indemnity Corporation, together with a Schedule identifying five other substantially identical Supplements to OPC Intercreditor and Security Agreements. (Filed as Exhibit 10.32.19(b) to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)

*10.13.20(a)	–	Surety Bond Implementation Agreement (P1), dated as of May 22, 2009, by and among Oglethorpe, Rocky Mountain Leasing Corporation, the Owner Participant named therein, U.S. Bank National Association, as Owner Trustee, U.S. Bank National Association, as Co-Trustee, Ambac Assurance Corporation and Berkshire Hathaway Assurance Corporation, together with a Schedule identifying four other substantially identical Surety Bond Implementation Agreements. (Filed as Exhibit 10.7 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.20(b)	–	Surety Bond Implementation Agreement (N5), dated as of August 19, 2009, by and among Oglethorpe, Rocky Mountain Leasing Corporation, NationsBanc Leasing & R.E. Corporation, as Owner Participant, U.S. Bank National Association, as Owner Trustee, U.S. Bank National Association, as Co-Trustee, Ambac Assurance Corporation and Berkshire Hathaway Assurance Corporation. (Referenced as Exhibit 10.7 in the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)
*10.13.21(a)	–	Berkshire Guaranty Agreement (P1), dated as of May 22, 2009, by and between Oglethorpe and Berkshire Hathaway Assurance Corporation, together with a Schedule identifying four other substantially identical Berkshire Guaranty Agreements. (Filed as Exhibit 10.8 to the Registrant's Form 8-K filed May 28, 2009, File No. 33-7591.)
*10.13.21(b)	–	Berkshire Guaranty Agreement (N5), dated as of August 19, 2009, by and between Oglethorpe and Berkshire Hathaway Assurance Corporation. (Referenced as Exhibit 10.8 to the Registrant's Form 8-K filed August 21, 2009, File No. 333-159338.)
*10.14.1(a)	–	Member Transmission Service Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia Transmission Corporation (An Electric Membership Corporation). (Filed as Exhibit 10.33.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.14.1(b)	–	Agreement to Extend the Term of the Member Transmission Service Agreement, dated as of August 2, 2006, by and between Oglethorpe and Georgia Transmission Corporation (An Electric Membership Corporation). (Filed as Exhibit 10.17.1(b) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006, File No. 33-7591.)
*10.14.2	–	Generation Services Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia System Operations Corporation. (Filed as Exhibit 10.33.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.14.3	–	Operation Services Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia System Operations Corporation. (Filed as Exhibit 10.33.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*10.15	–	Long Term Transaction Service Agreement Under Southern Companies' Federal Energy Regulatory Commission Electric Tariff Volume No. 4 Market-Based Rate Tariff, between Georgia Power Company and Oglethorpe, dated as of February 26, 1999. (Filed as Exhibit 10.27 to the Registrant's Form 10-Q for the quarterly period ended March 31, 1999, File No. 33-7591.)
*10.16	–	Credit Agreement, dated as of June 9, 2011, among Oglethorpe, as borrower, and the lenders identified therein, including Bank of America, N.A., as administrative agent (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed June 10, 2011, File No. 000-53908.)
*10.17[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and Thomas A. Smith. (Filed as Exhibit 10.19 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)

*10.18[3]	–	Employment Agreement, dated January 1, 2007, between Oglethorpe and Michael W. Price. (Filed as Exhibit 10.20 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.19[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and Elizabeth Bush Higgins. (Filed as Exhibit 10.21 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.20[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and William F. Ussery. (Filed as Exhibit 10.23 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.21[3]	–	Employment Agreement, dated as of August 17, 2009, between Oglethorpe and Charles W. Whitney (Filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2009, File No. 33-7591.)
*10.22	–	Oglethorpe Power Corporation Executive Incentive Payment Plan, dated November 8, 2007. (Filed as Exhibit 10.25 to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.)
*10.23	–	Participation Agreement for the Oglethorpe Power Corporation Executive Supplemental Retirement Plan, dated as of March 15, 2002, between Oglethorpe and Thomas A. Smith. (Filed as Exhibit 10.30 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2002, File No. 33-7591.)
12.1	–	Oglethorpe Computation of Ratio of Earnings to Fixed Charges, Margins for Interest Ratio and Equity Ratio
14.1	–	Code of Conduct, last revised July 25, 2011, available on our website, www.opc.com.
21.1	–	Subsidiaries of the Registrant and jurisdiction of incorporation/organization: Rocky Mountain Leasing Corporation, a Delaware corporation.
23.1	–	Consent of Ernst & Young LLP
23.2	–	Consent of PricewaterhouseCoopers LLP
31.1	–	Rule 13a-14(a)/15d-14(a) Certification, by Thomas A. Smith (Principal Executive Officer).
31.2	–	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).
32.1	–	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Thomas A. Smith (Principal Executive Officer).
32.2	–	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).
*99.1	–	Member Financial and Statistical Information (Filed as Exhibit 99.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
101	–	XBRL Interactive Data File.

(1) Pursuant to 17 C.F.R. 229.601(b)(4)(iii), this document(s) is not filed herewith; however the registrant hereby agrees that such document(s) will be provided to the Commission upon request.

(2) Confidential treatment has been requested for certain confidential portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934. In accordance with Rule 24b-2, these confidential portions have been omitted from this exhibit and filed separately with the SEC.

(3) Indicates a management contract or compensatory arrangement required to be filed as an exhibit to this Report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 20th day of March, 2012.

OGLETHORPE POWER CORPORATION
(AN ELECTRIC MEMBERSHIP CORPORATION)

By: /s/ THOMAS A. SMITH

THOMAS A. SMITH
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ THOMAS A. SMITH THOMAS A. SMITH	President and Chief Executive Officer (Principal Executive Officer)	March 20, 2012
/s/ ELIZABETH B. HIGGINS ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 20, 2012
/s/ G. KENNETH WARREN, JR. G. KENNETH WARREN, JR.	Vice President, Controller (Principal Accounting Officer)	March 20, 2012
/s/ C. HILL BENTLEY C. HILL BENTLEY	Director	March 20, 2012
/s/ BENNY W. DENHAM BENNY W. DENHAM	Director	March 20, 2012
/s/ WM. RONALD DUFFEY WM. RONALD DUFFEY	Director	March 20, 2012
/s/ M. ANTHONY HAM M. ANTHONY HAM	Director	March 20, 2012
/s/ MARSHALL MILLWOOD MARSHALL MILLWOOD	Director	March 20, 2012

Signature	Title	Date
/s/ JEFFREY W. MURPHY JEFFREY W. MURPHY	Director	March 20, 2012
/s/ DANNY L. NICHOLS DANNY L. NICHOLS	Director	March 20, 2012
/s/ G. RANDALL PUGH G. RANDALL PUGH	Director	March 20, 2012
/s/ J. SAM L. RABUN J. SAM L. RABUN	Director	March 20, 2012
/s/ BOBBY C. SMITH, JR. BOBBY C. SMITH, JR.	Director	March 20, 2012
/s/ GEORGE L. WEAVER GEORGE L. WEAVER	Director	March 20, 2012
/s/ H. B. WILEY, JR. H. B. WILEY, JR.	Director	March 20, 2012