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, 2009

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

OglethorpePowerCorporation

(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

2009 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 207 employees.

In December 2009, Flint EMC, which withdrew as a member in January 2005, became our 39th member. Currently, Flint does not have a percentage capacity responsibility from any of our operating generation resources; however, it is participating in generation resources under construction and has the right to participate in any future generation resources we may acquire or construct. Since Flint is not a participant in our operating generation resources, we do not supply any of its capacity or energy requirements. However, all the historical member statistics in this report include Flint.

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 this annual report on Form 10-K and information contained on this website 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. 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 29 operating generating units, fueled by nuclear, coal, gas, oil and hydro. (See "OUR POWER SUPPLY RESOURCES" and "PROPERTIES – Generating Facilities.")

In 2009, three of our members, Cobb EMC, Jackson EMC and Sawnee EMC, accounted for 15.0%, 11.6% and 10.2% of our total revenues, respectively. Each of our other members accounted for less than 10% of our total revenues in 2009.

Wholesale Power Contracts

The wholesale power contracts we have with each member are substantially similar and extend through December 31, 2050. 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 costs 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 costs 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 2009, we supplied energy that accounted for approximately 55% 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. Under the 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 indenture or by a lien equal or prior to the lien of the 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 costs 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 during the period 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, our board of directors approved budgets for 2009 and 2010 to achieve a 1.12 and 1.14 margins for interest ratio, respectively; each above the minimum 1.10 ratio required by the indenture. As our generation construction program evolves, our board of directors will continue to evaluate the level of margin coverage and may choose to further increase, or decrease, the margins for interest ratio in the future.

Under the 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. (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 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 have also purchased 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-based rates.

As of December 31, 2009, we had approximately $8.0 million of loans outstanding to Georgia System Operations, primarily for the purpose of financing capital expenditures. Georgia System Operations has an additional $6.0 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-guaranteed loan funds is subject to annual federal budget appropriations and thus cannot be assured. Currently, Rural Utilities Service-guaranteed loan funds are subject to increased uncertainty because of budgetary and political pressures faced by Congress. The President's budget for fiscal year 2011 proposes to reduce funding by almost 40% from 2010 levels and, in support of the President's commitment to reduce inefficient fossil-fuel subsidies, prohibits loans for new or existing fossil-fueled generation. The budget limits the use of electric loan funds to renewable energy, transmission, distribution and carbon-capture projects on generation facilities. 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-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 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 extent of the Rural Utilities Service's approval rights under the loan contract with us is substantially less than the supervision and control the Rural Utilities Service has traditionally exercised over borrowers under its standard loan and security documentation. In addition, the indenture improves our ability to borrow funds in the capital markets relative to the Rural Utilities Service's standard mortgage. The 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;
- additional 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, current legislative proposals include 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 (see "ENVIRONMENTAL AND OTHER REGULATIONS – Carbon Dioxide Emission and Climate Change – *Pending Legislation*" and "RISK FACTORS"). 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 would be available to us or our members under the current legislative proposals, would mitigate the impact, if any, on our and our members' competitiveness resulting from these legislative proposals, if enacted.

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.

Effective January 1, 2005, one of our members, Flint, withdrew from membership in us and assigned, with our consent, its wholesale power contract to Cobb EMC. A portion of the power supply resources covered by the Flint wholesale power contract was reallocated to six other members. Cobb also acquired Pataula EMC and provided us a guarantee of Pataula's payment obligations under its wholesale power contract. Other members could consider similar arrangements.

In December 2009, Flint again became one of our members. For further discussion regarding Flint, see " – General."

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 climate, whether as a result of greenhouse gas emissions or otherwise. 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 2009, we supplied approximately 55% of the retail energy requirements of our members.

Generating Plants

We have interests in 29 operating generating units. The Municipal Electric Authority of Georgia, the City of Dalton and Georgia Power also have interests in eight 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 treat 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 2009, 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 the Hawk Road Energy Facility 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.

Other Power System Arrangements

We have interchange, transmission and/or short-term capacity and energy purchase or sale agreements with approximately 50 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-third 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.

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 index-based adjustments, as well as adjustments for change orders and performance bonuses. This agreement was amended in February 2010. This amendment, which the parties agreed is subject to the approval of the Georgia Public Service Commission, replaces certain of the index-based adjustments with fixed escalation amounts.

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 permanently stop work, certain breaches of the contract by the Owners, Owner insolvency and certain other events.

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 August 2006, Southern Nuclear Operating Company, on behalf of the Owners, filed an application with the Nuclear Regulatory Commission for early site permits for these two additional units, and in March 2008 filed an application for combined construction permits and operating licenses for two 1,100 megawatt units, using the Westinghouse AP1000 technology.

Five entities intervened in the Plant Vogtle early site permit process. The Nuclear Regulatory Commission appointed an Atomic Safety and Licensing Board panel to rule on the contentions of the intervenors. After a hearing in March 2009, the Atomic Safety and Licensing Board panel found in favor of the Owners and the Nuclear Regulatory Commission, and against the intervenors.

In August 2009, the Nuclear Regulatory Commission issued the early site permit and a limited work authorization, allowing subsurface foundation work to proceed in advance of a combined construction permit and operating license. In October 2009, the intervenors in the aforementioned litigation filed a petition for review of the early site permit decision in the United States Court of Appeals for the District of Columbia.

An Atomic Safety and Licensing Board panel was also appointed to preside over hearings in the combined construction permit and operating license proceeding. The Board admitted one contention of intervenors for hearing. The Nuclear Regulatory Commission schedule for this proceeding contemplates a decision in fourth quarter 2011.

In August 2009, the Nuclear Regulatory Commission issued letters to Westinghouse revising the review schedules needed to certify the AP 1000 standard design for new reactors and expressing concerns related to the availability of adequate information and the shield building design. The shield building protects the containment and provides structural support to the containment cooling water supply. Southern Nuclear is continuing to work with Westinghouse and the Nuclear Regulatory Commission to resolve these concerns. Any possible delays in the AP 1000 design certification schedule, including those addressed by the Nuclear Regulatory Commission in their letters, are not currently expected to affect the projected commercial operation dates for Plant Vogtle Units No. 3 and No. 4.

Our estimated total costs for the new units, including allowance for funds used during construction, are approximately $4.2 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. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Capital Requirements – Capital Expenditures" and " – Financing Activities.*"

Biomass Plant

Our members have subscribed for a 100 megawatt biomass-fueled generating plant. We have acquired a site in Warren County, Georgia and are currently in the process of conducting preliminary engineering work and environmental analyses, acquiring major equipment, and requesting proposals for an engineering, procurement and construction contract. This plant is planned for commercial operation in 2014.

Our estimated cost to construct this facility is $477 million, including allowance for funds during construction. We have submitted a loan application to the Rural Utilities Service for financing of this project. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF

Financial Condition and Results of Operations – Financial Condition – *Capital Requirements – Capital Expenditures*" and " – *Financing Activities*."

We acquired a site for a second plant, which had been considered for commercial operation in 2015, but which has now been delayed for an indefinite period of time.

Combined Cycle Plant

Our members have also subscribed for a two on one, 605 megawatt, combined cycle plant with anticipated commercial operation in 2015. Current activities include site selection and environmental permitting. The estimated cost for this facility is approximately $750 million, including allowance for funds used during construction. We plan to submit a loan application to the Rural Utilities Service for financing of this project. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Condition – *Capital Requirements – Capital Expenditures*" and " – *Financing Activities*."

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"). In addition to Vogtle Units No. 3 and No. 4, the biomass plant and the combined cycle plant, we have identified for our members other generation resource development possibilities to help meet their power supply needs over the next ten years. Our members have given general approval for the future development of certain quantities of gas-fired combustion turbine plants and combined cycle plants that may be planned for commercial operation prior to December 31, 2016, subject to future member subscription for specific projects. We are continuing development activities to be prepared for construction as needed.

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

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 67% to residential consumers, 30% to commercial and industrial consumers and 3% to other 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 2007 through 2009, and also shows the amount of their energy requirements that we supplied. From 2007 through 2009, demand and energy requirements of the members declined at an average annual compound rate of 4.5% and 1.1%, respectively. This decline is the result of milder weather and general economic conditions in 2008 and 2009.

	Member Demand (MW)	Member Energy Requirements (MWh)	
	Total(1)	Total(2)	Supplied by Oglethorpe(3)
2007	9,292	37,652,829	22,815,174
2008	8,947	37,530,578	23,308,911
2009	8,470	36,793,085	20,191,657

(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, 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 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 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 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.

As requested by the President, Congress adopted a 2010 budget that continued funding the Rural Utilities Service at the same level as 2009. However, the President's budget proposal for fiscal year 2011 proposes to reduce funding by almost 40% 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. 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 our members, including Georgia Transmission and us, to provide to them the services that it 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 additional information about our members' relationship with Georgia System Operations, see ''OGLETHORPE POWER CORPORATION – Relationship with Georgia System Operations.''

Member Power Supply Resources

Oglethorpe Power Corporation

In 2009, we supplied approximately 55% 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 costs 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 the Hawk Road Energy Facility. (See ''OUR POWER SUPPLY RESOURCES – Power Purchase and Sale Agreements – *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 (SEPA) under contracts that extend until 2016. In 2009, 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 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.''

Georgia Power Block Purchase

Thirty members have entered into 10-year power supply contracts with Georgia Power under which they purchase an aggregate of 750 megawatts of capacity and associated energy. Delivery under the agreements began January 1, 2005.

Other Member Resources

Our members are obtaining their remaining power supply requirements from various sources. Thirty-one members have entered into contracts with third parties for all of their incremental power requirements, with remaining terms ranging from 4 to 7 years. Some contracts, for fixed quantities, extend more than 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 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, such as particulate matter, sulfur dioxide and nitrogen oxides into the air and discharges of other pollutants, including heat, into 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. New requirements 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 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.*''

Clean Air Act

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 and other pollutants from affected electric utility units, including the coal-fired units at Plants Wansley and Scherer.

Sulfur dioxide reductions are being imposed through a sulfur dioxide emission allowance trading program established under the 1990 amendments to the Clean Air Act. Pursuant to regulations issued by the U.S. Environmental Protection Agency, or EPA, aggregate emissions of sulfur dioxide from all affected units are now capped at 8.9 million tons per year. Tradable emission allowances, which authorize the emission of one ton of sulfur dioxide during a particular calendar year or thereafter, are issued 30 years in advance and are transferable. We are currently complying with this program by using lower-sulfur fuel and emission allowances. Flue gas desulfurization equipment, commonly known as scrubbers, was installed and placed in service in July 2009 at Plant Wansley and is in the design phase at Plant Scherer to comply with these regulations and with other regulations discussed below.

Reductions in nitrogen oxides emissions were also imposed, under the prior 1-hour National Ambient Air Quality Standard (NAAQS) for ozone, requiring the installation of new control equipment. Significant reductions in nitrogen oxides emissions were achieved, due to the selective catalytic reduction systems installed at Plant Wansley and the separated overfire air systems installed at Plant Scherer.

Other recently finalized regulations, proposed regulations and other actions could result in more stringent controls on all emissions, including utility emissions. The actions that appear to be the most significant are described below. These regulatory programs affect existing fossil fuel-fired generating facilities, and could also impact future fossil fuel-fired generating plants.

8-hour Ozone NAAQS. When the old 1-hour ozone NAAQS was replaced with the new, more stringent 1997 8-hour standard, the Atlanta ozone nonattainment area was expanded in 2005 from its original 13 counties to 20 counties, and the Macon ozone nonattainment area (which includes Plant Scherer) was created. Litigation challenging implementation of the 1997 8-hour standard continues in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), with a decision expected on most issues in the near future.

With regard to the 1997 standard, the Atlanta area has been reclassified to a more stringent nonattainment status and the Macon area was designated as attainment. In March 2008, EPA issued a final rule further tightening the 8-hour standards. In March 2009, the Georgia Environmental Protection Division recommended that Bibb County, which includes Macon, and a portion of Monroe County, which includes Plant Scherer, be designated as nonattainment under the 2008 standard. The State also recommended that the Atlanta area be expanded to include that portion of Heard County where Plant Wansley is located. Other nonattainment areas are also recommended. A state implementation plan (SIP) to bring the Atlanta area into attainment with the 1997 standard was due at the end of 2008 and a final SIP was submitted to EPA in September 2009. However, that SIP does not yet demonstrate attainment of the 1997 standard by the 2010 deadline. Monitored values of ozone are decreasing and may provide relief from the imposition of a bump-up to a new, more stringent classification for the Atlanta area based on the 1997 standard. Implementation of certain aspects of the new 2008 standard is currently subject to ongoing rulemaking. In January 2010, EPA issued a formal reconsideration of the 2008 standard, proposing to stay any designations associated with the 2008 standard, to tighten such standard in a final rule by August of 2010 and to require SIPs for any nonattainment areas by December 2013.

Particulate Matter NAAQS. Plants Wansley and Scherer are in areas designated in 2005 as nonattainment for the fine particulate matter standards first established in 1997. An implementation rule was finalized in 2007 setting forth how the 1997 standards are to be met, and a SIP for achieving 1997 standards in this area was due in 2008, but is still under development. A second implementation rule was finalized in May 2008, setting forth how new source review provisions are to be implemented for fine particulate matter. Litigation on these implementation rules continues in the D.C. Circuit. In April 2009, EPA announced reconsideration of certain aspects of the 2008 implementation rule and finalized a rule in September 2009 staying certain provisions of the 2008 rule. That 2009 rule has also been challenged. While in 2006 the 1997 short-term standards for fine particulate matter were tightened, no new areas were designated in Georgia as nonattainment for the revised standards. On February 24, 2009, however, the D.C. Circuit remanded the 2006 long-term standards for fine particulate matter back to EPA for further review. Implementation of any standards for fine particulate matter that might be revised due to the remand will be the subject of future rulemaking.

Regional NO_x SIP Call. In 1998 and 2004, EPA promulgated regulations for a 22-state region, which included Georgia, imposing a cap on nitrogen oxides emissions in the affected region, and requiring each state in the region to revise its SIP to implement the necessary reductions. In 2005, EPA stayed the implementation of that rule as it would apply to Georgia. In 2008, EPA finalized a rule that deleted Georgia from these regulations. North Carolina challenged the 2008 rule in the D.C. Circuit, and the Georgia Coalition for Sound Environmental Policy, of which we are a member, subsequently intervened in that litigation. In November 2009, the D.C. Circuit dismissed North Carolina's petition. As North Carolina failed to appeal this ruling the case has now become final, as has the stay exempting Georgia from these rules.

Clean Air Interstate Rule. EPA finalized the Clean Air Interstate Rule (CAIR) in 2005 for ozone and fine particulate matter, which requires emissions reductions in sulfur dioxide and nitrogen oxides in most eastern states, including Georgia. The rule established a market-based cap and trade program, with emission caps for each affected state. Under Georgia's SIP, which now includes the rule, the caps are to be implemented in two phases. The phase one caps for nitrogen oxides took effect in 2009, and for sulfur dioxide are scheduled to become effective in 2010. A second phase for both pollutants follows in 2015. While the D.C. Circuit initially vacated CAIR in its entirety, in a subsequent decision the Court instead simply remanded the rule to EPA without vacatur, leaving it in place until EPA issues a new rule consistent with the Court's decision. As a result of these actions, more stringent regulatory limits could be imposed, or there may be a change (delay or acceleration) in the effective dates of federal requirements to reduce emissions. Based on the D.C. Circuit's decision, EPA may not be able to use emissions trading or the surrender of Title IV sulfur dioxide allowances to achieve the goals of the program, and may require sources to meet new, more stringent sulfur dioxide emission limitations instead. EPA is expected to propose a CAIR replacement rule by July

2010, and any new standards will be the subject of this or other future rulemakings.

Regional Haze. EPA's 1999 regional haze rule was created for the control of certain sources that emit nitrogen oxides or sulfur dioxide that contribute to the degradation of visibility in mandatory federal Class I areas, such as national parks and wilderness areas. A revised rule was issued in 2005 to address portions of the 1999 rule remanded to EPA. Another rule and guidance to implement the regional haze rule were also proposed by EPA in 2005. The goal of the regional haze rule is to restore natural visibility conditions in the Class I areas by 2064. Interim milestones reflecting reasonable progress towards this goal are required beginning in 2018. Moreover, the rule requires the application of best available retrofit technology for a certain class of sources (including Plants Scherer and Wansley) contributing to the impairment of visibility in the Class I areas. The Georgia SIP to implement best available retrofit technology and reasonable further progress, originally due in December 2007, was submitted in February 2010 to EPA. While the current SIP calls for no further controls for Plants Scherer or Wansley, it remains subject to EPA review and approval.

Short-term NAAQS for Sulfur Dioxide. In November 2009, EPA proposed to strengthen the primary standard for sulfur dioxide, by replacing the current annual and 24-hour standards with a new, more stringent one hour standard. Changes would include siting of future monitors for measuring short-term ambient concentrations of sulfur dioxide. While no changes have been proposed to the secondary standard, EPA has indicated that it is considering such changes pursuant to a separate review.

Short-term NAAQS for Nitrogen Dioxide. In January 2010, EPA established a new, primary 1-hour standard for nitrogen dioxide. EPA is also requiring changes to its monitoring requirements for nitrogen dioxide, by establishing a new monitoring network, principally in urban areas, requiring that such new monitors be installed and operational by January 2013. EPA has indicated that this new standard must be taken into account when permitting new or modified sources of NO_x emissions such as fossil fuel-fired power plants.

Clean Air Mercury Rule and State-Related Mercury Rules. In 2005, EPA finalized a regulation that would control emissions of mercury, by creating a market-based cap-and-trade program that would reduce emissions of mercury in two phases, with the first phase becoming effective in 2010 and the second in 2018. In early 2008, the D.C. Circuit vacated and remanded this rule and a companion regulation delisting electric generating units from the hazardous air pollutant source list in Section 112 of the Clean Air Act. Appeal of this decision to the U.S. Supreme Court was dismissed. While Georgia elected to include the EPA cap-and-trade program in its SIP, the outcome of this litigation has negated that portion of Georgia's plan. Recently, EPA indicated its intent to conduct rulemakings that would set maximum achievable control technology limits for certain hazardous air pollutants (that would include mercury) for coal and oil-fired electric generating units, proposing such rules by March 2011 and finalizing such regulations by November 2011. In addition, EPA has issued an information collection request to collect data intended for use in such rulemakings. Georgia's mercury rules include a "multi-pollutant rule" that requires operation of the existing selective catalytic reduction systems (nitrogen oxides) and scrubbers (sulfur dioxide and mercury) being installed at Plant Wansley as well as additional controls for mercury (activated carbon injection and baghouse), sulfur dioxide (scrubber) and nitrogen oxides (selective catalytic reduction system) at Plant Scherer. The maximum achievable control technology rulemaking for mercury and other hazardous air pollutants might affect current state rules like the multi-pollutant rule, and might require other rules or revisions to Georgia's SIP.

New Source Review. In November 1999, the United States Justice Department, 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, among other facilities, Scherer Unit Nos. 3 and 4. We are not currently named in the lawsuits and we do not have an ownership interest in the named units of Plant Scherer. However, we can give no assurance that units in which we have an ownership 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 required to remedy our violations at co-owned facilities.

Rulemakings that could impose new source review requirements on greenhouse gases (including carbon dioxide) under the Prevention of Significant Deterioration (PSD) preconstruction permitting program began in earnest last year. After a September 2009 rule regulating greenhouse gas emissions from new motor vehicles and an October 2009 rule applying the motor vehicle rule to stationary sources were proposed, EPA issued a final rule in December 2009 determining that certain greenhouse gas emissions from new motor vehicles, including carbon dioxide, endanger public health or welfare. Until very recently, EPA indicated its intent to finalize these proposed rules and other proposed rules by the Spring of 2010, such that certain greenhouse gases (including carbon dioxide) would become regulated pollutants for stationary sources (including power plants) under the PSD preconstruction permitting and the Title V operating permit programs at that time. In late February of 2010, however, EPA indicated that PSD for major stationary sources would not be triggered before January 1, 2011.

Clean Air Act 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 (1) several of these proposed or final Clean Air Act regulations could require control of the same emissions, (2) the compliance requirements remain uncertain, (3) litigation challenging some or all of these rules is likely, and (4) 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 operation expenses for the continued operation of 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 to increase. Such limitations on emissions could originate in the Congress, the executive branch or the courts. International developments may also influence the development of any laws to control emissions or carbon dioxide from power plants.

Pending Legislation. Congressional legislative proposals being considered would impose new types of regulation or more stringent emissions limitations for greenhouse gases, including carbon dioxide, on power plants. In June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009 (H.R. 2454), also known as the Waxman-Markey bill, which would establish, among other things, a cap-and-trade system (starting at 17% below 2005 levels by 2020, tightening to 83% by 2050) for greenhouse gas emissions in the U.S. The bill also includes a national renewable electricity standard, which would begin at 6% of retail sales in 2012, increase to 20% in 2020, and remain at that level through 2039. While we will not be subject to the annual renewable electricity standard – it would apply only to retail electric suppliers that sell at least 4,000,000 megawatt hours of electricity to retail consumers – initially two of our members would be subject to the standard. We are currently pursuing the construction of a 100 megawatt renewable biomass power generation facility in Georgia that we believe would qualify under the bill's renewable electricity standard. Senate legislation and initiatives, like the Clean Energy Jobs and American Power Act of 2009, the American Clean Energy Leadership Act of 2009 and the Kerry – Lieberman – Graham framework could produce results similar to H.R. 2454. We cannot predict at this time whether any legislative actions will result in a renewable electricity standard applicable to our members or in the regulation of greenhouse gas emissions from our power plants, nor can we predict the impacts from any relevant federal legislation. Emissions of carbon dioxide from our plants totaled approximately 10 million short tons in 2009.

Executive Branch Action. In 2007, the U.S. Supreme Court ruled in *Massachusetts v. EPA* 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. The Court directed EPA to decide whether such regulation is needed. In response, and as a reflection of current Administration priorities, EPA issued a final rule in December 2009 determining that certain greenhouse gas emissions (including carbon dioxide) from new motor vehicles endanger public health or welfare. Other relevant rules, while not yet finalized, could lead to the direct regulation of greenhouse gas emissions from power plants. In September 2009, EPA proposed a rule relating to the regulation of greenhouse gases from light-duty vehicles. In October 2009, EPA proposed another rule conveying its interpretation of when a pollutant (such as a greenhouse gas like carbon dioxide) becomes ‘‘subject to regulation’’ under the Clean Air Act. Also in October 2009, EPA proposed significance thresholds for greenhouse gas emissions, to determine when new or modified stationary sources could trigger new source review and issued a rule requiring the annual reporting (beginning in 2011 for 2010 emissions) of greenhouse gas emissions by many industries, including the electric utility industry, and by fossil fuel suppliers. Until very recently, EPA has stated its intention to finalize these proposed rules in the Spring of 2010, and has taken the position that these rules when finalized would begin the process of regulating emissions of greenhouse gases from both mobile and stationary sources. In late February of 2010, however, EPA indicated that new source review for major stationary sources of greenhouse gas emissions would not be triggered before January 1, 2011. Finally, EPA has stated its intention to issue a revised New Source Performance Standard (NSPS) for steam generating units operated by electric utilities (and other industrial and commercial facilities) in 2010. That rulemaking is in response to a petition for review of EPA’s refusal to adopt regulations governing power plant emissions of carbon dioxide and other greenhouse gases under the Clean Air Act. After the Supreme Court reached its decision in *Massachusetts v. EPA*, the U.S. Court of Appeals for the D.C. Circuit remanded the case back to EPA in September 2007 for further proceedings in light of that decision. Both of the final rules discussed above are subject to numerous petitions for review, and challenges to the remaining rules may be brought if and when such rules are finalized. We cannot predict at this time whether these developments will ultimately result in the regulation of greenhouse gas emissions from our power plants, or the effects of any such regulation.

Litigation. Litigation related to carbon dioxide emissions continues on numerous fronts, and the outcome of such litigation could affect the power plants we own. 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 2005, the Court granted the defendants’ motions to dismiss, which the plaintiffs appealed in October 2005. In September 2009, the U.S. Court of Appeals for the Second Circuit ruled in favor of the plaintiffs, vacating dismissal of their claims and remanding the case back to the district court. In November defendants sought rehearing in the case, which also is subject to a potential appeal.

In an October 2009 decision involving common law claims for both injunctive relief and property damage allegedly caused by greenhouse gas emissions, the U.S. Court of Appeals for the Fifth Circuit reversed the U.S. District Court for the Southern District of Mississippi’s dismissal of private property claims against certain oil, coal, chemical and utility companies alleging damages from Hurricane Katrina. In reversing the case, the Fifth Circuit held that plaintiffs have standing to assert their nuisance, trespass and negligence claims. Contrary to the decision of the District Court, the Fifth Circuit concluded that these claims were not barred by the political question doctrine where, under separation of power principles, federal courts decline to rule on questions deemed more appropriate for action first by Congress or the Executive Branch. In March of 2010, however, the Fifth Circuit agreed to a rehearing of the case before the entire Court.

In February 2008, the Native Village of Kivalina and the City of Kivalina filed suit in the U.S. District Court for the Northern District of California against several electric utilities, several oil companies and one coal company, alleging that their village in Alaska is being destroyed by erosion caused by global warming attributable to defendants’ greenhouse gas emissions. The plaintiffs assert claims for public and private nuisance and seek damages, on a joint and several basis and in the range of \$95 million to \$400 million from defendants for lost property values and the costs of relocating the village. In September of 2009, the district court granted defendants’ motions to dismiss the case, ruling the plaintiffs lacked standing to bring the case and that plaintiffs' claims were barred by the political question doctrine. Plaintiffs appealed the case to the U.S. Court of Appeals for the Ninth Circuit in November of 2009.

In June 2008, a Fulton County, Georgia Superior Court Judge overturned an air quality permit issued to Longleaf Energy Associates, LLC for the construction of a coal-fired power plant in Early County, Georgia. This permit had previously been upheld by the Office of State Administrative Hearings (OSAH) after an appeal by the Sierra Club and Friends of the Chattahoochee. The judgment set aside OSAH's decision, concluding that carbon dioxide emissions are regulated and thus require permitting under the Clean Air Act. On appeal, the decision was reversed by the Georgia Court of Appeals. The case was, for other reasons, remanded for further OSAH evidentiary proceedings unrelated to the carbon dioxide issue. Sierra Club and Friends of the Chattahoochee applied for discretionary appeal of the case to the Georgia Supreme Court, which in September 2009, decided not to hear the appeal. Recently, Sierra Club and Friends of the Chattahoochee filed a motion for reconsideration with the Georgia Supreme Court. That motion was denied, ending the appeal. Ongoing litigation and administrative review actions are pending in other states, where, like the Georgia case, it is being argued that best available control technology is required for carbon dioxide emissions from new or modified sources under the Clean Air Act. We cannot predict at this time whether any of these actions will result in the regulation of greenhouse gas emissions from our power plants, or the effects of any such regulation.

Other issues raised by global climate change are also being litigated in courts throughout the United States. For example, a current case in the United States District Court for the District of Columbia (*Sierra Club v. USDA, et al.*; No. 07-1860) is based on an argument that the consents or approvals issued by the Rural Utilities Service in its capacity as a lender for a coal-fired power plant constitute a major federal action triggering the review requirements of the National Environmental Policy Act (NEPA), which requires federal agencies to assess the environmental impacts of their major actions. Other litigation addresses the extent to which any reviewing federal agency must consider the impact of greenhouse gas emissions in the National Environmental Policy Act review process. In February 2010, the Council on Environmental Quality issued draft guidance confirming that federal agencies, when conducting their scoping reviews under NEPA, should consider whether an analysis of direct and indirect emissions of greenhouse gases from their proposed actions may provide meaningful information to decision-makers and the public. Federal agencies are instructed to consider not only whether evaluated actions may increase emissions of greenhouse gases, but also the relationship climate change effects may have on proposed and considered actions. Given the broad nature of these inquiries, we cannot currently predict how greenhouse gas emissions issues will arise in connection with our pending or future interaction with federal agencies, including the pursuit of necessary consents, approvals or permits, or whether litigation based on climate change issues will adversely affect our construction and development plans.

International Developments. International climate change negotiations under the United Nations Framework Convention on Climate Change continue. In the latest round of formal discussions in Copenhagen in December of 2009, nonbinding agreements were reached that included a pledge from participating countries to reduce their emissions of greenhouse gases. The outcome and impact of these international negotiations cannot be determined at this time.

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.

Other Environmental Regulation

After the release of over five million cubic yards of fly ash from a power plant ash storage facility in Tennessee in December 2008, EPA has been under increased pressure to regulate the handling and storage of coal combustion products at the federal level. Coal combustion waste disposed in landfills and surface impoundments is currently a regulated solid waste only at the state level and in most cases is not considered a hazardous waste. As part of a 2000 regulatory determination, EPA had been developing national solid waste management standards to address coal combustion waste and is continuing to consider whether coal combustion waste may continue to be classified as non-hazardous under the Resource Conservation and Recovery Act. The new standards, expected in early 2010, will likely include increased groundwater monitoring, more stringent siting requirements and closure of existing coal waste management facilities not meeting minimum standards. EPA has requested information on current ash impoundments at coal-fired power plants and is continuing to evaluate the safety of these structures. In January 2010, EPA also proposed to include the electric utility industry among those for which it plans to develop proposed regulations identifying appropriate financial responsibility requirements under the Comprehensive Environmental Response, Compensation, and Liability Act. Depending on the outcome of these rulemakings, we may incur substantial additional costs for the management, beneficial use and disposal of these wastes.

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. Upon completion of the study, EPA announced in late 2009 its intention to revise these guidelines, proposing to adopt such revisions by 2013. We cannot predict at this time whether any such regulations by EPA, or any action by the State of Georgia, will impact the current methods of wastewater or ash disposal utilized at our plants.

In February 2008, the Georgia legislature adopted a comprehensive state water plan for Georgia. The stated purpose of this plan is to guide Georgia in managing water resources in a sustainable manner to support the state's economy, to protect public health and natural systems, and to enhance the quality of life for all citizens. The plan lays out statewide policies, management practices, and guidance for regional planning. The provisions of this plan are intended to guide river basin and aquifer management plans and regional water planning efforts statewide in a manner consistent with existing state law. Power generation is a key use of water in the state, and any regulations or other enforceable requirements developed in response to this plan or subsequent regional plans may have substantial effects on the operations of our facilities or future facilities we construct or acquire. The impacts of this water plan cannot be determined at this time and will depend on the development of future implementing regulations.

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, some of which are being reviewed by Congress, could affect many areas of our operations. Although compliance with new environmental legislation could have a significant impact on us, those impacts cannot be fully determined at this time and would depend in part on the final legislation and the development of implementing regulations.

We, or generating facilities in which we have an interest, 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, however, do not believe that the current actions will have a material adverse effect on our financial position or results of operations.

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.

Applications have been filed with the Nuclear Regulatory Commission for an early site permit and for combined construction permits and operating licenses that would allow the construction and operation of two additional units at Plant Vogtle. See "OUR POWER SUPPLY RESOURCES – Future Power Resources."

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 outcome 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 2015. 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

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 subject to licensing by the Federal Energy Regulatory Commission.

We have a license, expiring in 2027, for Rocky Mountain. 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.

The Energy Policy Act of 2005 amended the Federal Power Act to authorize the Federal Energy Regulatory Commission to establish regional reliability organizations authorized to enforce reliability standards and to establish clear responsibility for the commission to prohibit manipulative energy trading practices. As a generation owner and participant in wholesale power transactions, we could be subject to penalties for violation of these standards and regulations.

ITEM 1A. RISK FACTORS

The following describes the most significant risks, in management's view, that may affect our business and financial condition. 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 undertaking a large capital expansion program that will significantly increase our long-term debt.

We are undertaking a large capital expansion program to meet the future energy needs of our members, and we will incur a significant amount of long-term debt in connection with this capital expansion program. As of December 31, 2009, we had $4.3 billion of long-term debt outstanding. For 2010 through 2017, we project that we will invest approximately $6.0 billion to $8.0 billion in new generation facilities and upgrades to our existing generation facilities. As a result of this program, we project that we will have approximately $10.0 billion in long-term debt outstanding by the end of 2017. 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 expected to increase the cost of electric service we provide to our members. In addition, we will continue to be highly leveraged and certain of our financial metrics may weaken, which could impact our credit ratings. To address this situation, our board of directors approved budgets for 2009 and 2010 to achieve 1.12 and 1.14 margins for interest ratios, respectively; each above the minimum 1.10 margins for interest ratio required under the indenture. However, even with these higher margins, due to the amount of incremental debt associated with new generation construction, our equity ratio will continue to decrease during the period of construction. Any reduction in our credit ratings could increase our borrowing costs and decrease our access to the credit and capital markets.

We are exposed to cost uncertainty in connection with our construction projects at existing and new generating facilities.

Our existing facilities require ongoing capital expenditures in order to maintain efficient and reliable operations. Many of our facilities were constructed over 20 to 30 years ago and, as a result, may require significant capital expenditures in order to maintain efficiency and reliability, and to comply with changing environmental requirements. In addition, due to projected growth in their service territories as well as the expiration or renegotiation of certain of their supplemental power supply agreements, our members have requested that we expand our existing generating facilities and build or acquire new generating facilities, which will require significant capital expenditures and investment.

The completion of construction projects without delays or cost overruns is subject to substantial risks, including:

- potential contract disputes;
- shortages and inconsistent quality of equipment, materials and labor;
- work stoppages;
- permits, approvals and other regulatory matters;
- adverse weather conditions;
- unforeseen engineering problems;
- environmental and geological conditions;
- delays or increased costs to interconnect our facilities to transmission grids;
- unanticipated increases in the costs of materials and labor;
- performance by engineering, construction or procurement contractors;
- increases in our cost of debt financing; and
- attention to other projects.

In addition, the construction of large generating plants involves significant financial risk. Moreover, no nuclear plants have been constructed in the United States using advanced designs. 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 could be exposed to additional risk of cost uncertainty in connection with future projects.

All of 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.

Due in part to national initiatives and/or international negotiations, we may become subject to legislative, regulatory and/or judicial responses to climate change, compliance with which could be difficult and costly.

Efforts to limit emissions of carbon dioxide from power plants continue to increase. EPA has issued an Advance Notice of Proposed Rulemaking that suggests various alternatives for regulating greenhouse gases under the Clean Air Act. EPA has also made an ''endangerment finding'' for carbon dioxide, which, if carried through, would trigger a series of events that could result in the regulation of carbon dioxide as an air pollutant. Many of our electric generating facilities are likely to be subject to regulation under climate change laws and/or regulations which result from these activities within the next few years. In 2009, our generation resources emitted approximately 10 million short tons of carbon dioxide. In 2009, 41% of our generation, excluding pumped storage, came from our interest in the coal-fired Plants Scherer and Wansley, which would be the most impacted by any greenhouse gas related legislation or regulation, while another 12% came from our gas-fired facilities (which would also be somewhat impacted but not to the same extent as the coal-fired facilities). The remaining generation (47%) came from our interest in the nuclear Plants Vogtle and Hatch and would not likely be impacted by any climate change legislation or regulation.

Many of the climate change legislative proposals use a ''cap-and-trade'' policy structure, in which carbon dioxide and other greenhouse gas emissions from some portion of the economy would be subject to an overall cap, which would decrease (i.e., become more stringent) over time. For example, the Waxman-Markey bill, which was passed by the House of Representatives in June 2009, proposes to enact a cap-and-trade regime in order to regulate carbon dioxide and other greenhouse gas emissions. Senate proposals are similar. Generally, the proposals establish mechanisms for emissions sources, such as power plants, to obtain ''allowances'' or permits to emit carbon dioxide and other greenhouse gases during the course of the year, somewhat similar to the emission allowance trading program for sulfur dioxide established by the Clean Air Act Amendments of 1990. However, unlike the program for sulfur dioxide, we and other utilities may need to purchase all or many of the necessary allowances in an auction format, rather than being issued allowances at no additional cost.

Litigation over climate change issues, including greenhouse gas emissions has become more frequent in the United States. Such suits involve claims of various types, including property damage, personal injury, common law nuisance, including injunctive relief, challenges to issued permits and citizen enforcement of the Clean Air Act.

International climate change negotiations under the United Nations Framework Convention on Climate Change continue. Nonbinding agreements to reduce emissions of greenhouse gases were made pursuant to the latest round of formal discussions late last year, and subsequent developments could produce binding obligations for emissions reductions.

The cost impact of legislation, regulation, new judicial interpretations of existing laws or regulations, or international obligations would depend upon the specific requirements created and cannot be determined at this time. For example, the impact of currently proposed legislation relating to greenhouse gas emissions would depend on a variety of factors, including the specific greenhouse gas emission limits or renewable energy requirements, the timing of implementation of these limits or requirements, the level of emissions allowances allocated and amounts that must be purchased, the purchase price of emissions allowances, the development of technologies for renewable energy and the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment, if any, and the impact on coal and natural gas prices.

Our access to, and cost of, capital could be adversely affected by various factors, including current market conditions, limitations on the availability of Rural Utilities Service loans and our credit ratings, and significant constraints on our access to, or increases in our cost of, capital 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. 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. In addition, a new wave of generation construction nationwide among electric cooperatives is resulting in increased competition for available Rural Utilities Service funding. The President's budget for fiscal year 2011 proposes to reduce funding by almost 40% from 2010 levels and, in support of the President's commitment to reduce inefficient fossil-fuel subsidies, prohibits loans for new or existing fossil-fueled generation. The budget limits the use of electric loan funds to renewable energy, transmission, distribution and carbon-capture projects on generation facilities. 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-guaranteed loans that may be available to us in the future.

We have applied for partial funding from the Federal Financing Bank, coupled with a guarantee from the Department of Energy, to fund our share of the cost of constructing two additional nuclear units at Plant Vogtle. On February 16, 2010, the Department of Energy presented us with a conditional term sheet that set forth the general terms of the loan and offered a guarantee that would target 70% of eligible project costs, not to exceed $3.057 billion. We have until May 17, 2010 to accept the terms of the conditional term sheet. We will work with the Department of Energy to finalize the loan guarantee. However, final approval and issuance of a loan guarantee by the Department of Energy is subject to receipt of the combined construction permits and operating licenses for Vogtle Units No. 3 and No. 4 from the Nuclear Regulatory Commission (a decision is currently anticipated in fourth quarter 2011), 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 further decreased or eliminated or we are unable to ultimately secure Department of Energy-guaranteed loan funds, we would have to seek alternative sources of 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, particularly in light of the significant amount of new generation construction that we have planned over the next decade to meet the future energy needs of our members. We have successfully accessed the capital markets in the past, and believe that we will be able to maintain sufficient access to the 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. Our borrowing costs could increase and our potential pool of investors, funding sources and liquidity could decrease if our credit ratings are lowered, particularly if our ratings are lowered below investment grade.

The cost of our debt financing is affected by prevailing interest rate levels, and if these interest rate levels increase at the time we issue fixed rate debt or reset the interest rates on our variable rate debt, our interest costs will increase and our financial condition and future results of operations could be adversely affected.

In addition, certain market disruptions could constrain, at least temporarily, our ability to maintain sufficient liquidity and to access capital on favorable terms or at all. These disruptions include:

- market conditions generally, such as the current uncertainty in the credit and capital markets;

- economic downturns or recessions;
- instability in the financial markets;
- a tightening of lending and lending standards by banks and other credit providers;
- the overall health of the energy industry;
- negative events in the energy industry, such as a bankruptcy of an unrelated energy company;
- 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 for any of the reasons stated above, or for any other reason, our ability to finance ongoing capital expenditures required to maintain existing generating facilities and to construct or acquire future power supply facilities could be limited, our interest costs could increase 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 25% of our generating capacity. Our ownership interest in these facilities exposes 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 required by the Nuclear Regulatory Commission;
- potential liabilities arising out of nuclear incidents or terrorist attacks, 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.

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 expected cost of decommissioning our nuclear facilities; however, it is possible that decommissioning costs and liabilities could exceed the amount of these funds.

The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of these facilities. If these 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. In addition, while we have no reason to anticipate a serious incident at either of these plants, if an incident did occur, it could result in substantial costs to us. 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 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*."

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years, and we may face increased costs related to environmental compliance, litigation 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.

Generally, these environmental regulations are becoming increasingly stringent and may require us to change the design or operation of existing facilities or change or delay the location, design, construction or operation of new facilities. These changes, in turn, may result in substantial increases in the cost of electric service. For example, the EPA, has indicated its intent to propose new regulations on the handling and disposal of coal combustion by-products. To date, we have committed significant capital expenditures to achieve and maintain compliance with these 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 requirements. Failure to comply with these 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.

Additionally, litigation relating to environmental issues, including claims of property damage or personal injury caused by 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 any such litigation would have a material adverse effect on our financial condition, 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 the environment may be adopted or become applicable to our facilities. Revised or additional laws and regulations, and in particular climate change legislation or 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 financial impact of any legislation or regulation would depend upon the specific requirements enacted and cannot be determined at this time.

We could be adversely affected if we 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 failure or operator error;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- compliance with mandatory reliability standards, including mandatory cyber security standards;
- labor disputes or shortages;
- fuel, water or material supply interruptions;
- terrorist attacks; or
- catastrophic events such as fires, earthquake, 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.

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 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 financial difficulties faced by other companies could adversely affect us.

We have exposure to many different industries and counterparties, and routinely execute transactions with counterparties in the energy industry, such as coal and natural gas companies, and the financial services industry, including commercial banks, investment banks and other institutions. Many of these transactions expose us to credit risk in the event of default of our counterparty. For example, we enter into hedge agreements to manage a portion of our exposure to fluctuations in the market price of natural gas with several counterparties. If our counterparties fail or refuse to honor their obligations, our hedges of the related risk may be ineffective. Any failure could significantly increase the cost of electric service we provide to our members.

Also, as a result of recent market events, some of our financial institution counterparties 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 obligations to us. For example, in 2008, the credit downgrades of AMBAC Indemnity Corporation and American International Group, Inc. triggered certain requirements under certain of our agreements which have now been satisfied. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Off-Balance Sheet Arrangements-Rocky Mountain Lease Arrangements*."

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, as a result of current economic conditions, sales by our members may not be sufficient to cover current 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, microturbines, 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.

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)

(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) 2009	2008	2007	Capacity Factor(3) 2009	2008	2007
Plant Hatch							
Unit No. 1	262.8	93%	83%	97%	93%	84%	98%
Unit No. 2	264.9	67	96	87	67	96	87
Plant Vogtle							
Unit No. 1	345.0	89	89	100	91	91	101
Unit No. 2	345.6	99	86	83	100	88	84
Plant Wansley							
Unit No. 1	258.9	87	98	83	51	85	77
Unit No. 2	258.9	95	88	98	45	72	91
Combustion Turbine(4)	0	61	60	44	0	0	0
Plant Scherer							
Unit No. 1	498.7	79	97	86	70	90	80
Unit No. 2	502.2	81	97	90	72	92	85
Rocky Mountain(5)							
Unit No. 1	272.3	74	97	86	18	26	22
Unit No. 2	235.0	96	93	97	19	21	25
Unit No. 3	272.3	75	76	37	15	11	6
Doyle(5)(6)	348.0	100	95	92	1	1	2
Talbot(5)	663.6	94	94	90	1	1	3
Chattahoochee	477.0	91	88	91	53	34	38
Hawk Road(7)	487.0	94	n/a	n/a	0	n/a	n/a
Hartwell(7)	298.0	99	n/a	n/a	3	n/a	n/a
TOTAL	5,790.2						

(1) Summer Planning Reserve Capacity is the amount used for 2010 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 operating performance factors for Hawk Road and Hartwell, which were 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 28, 2010, we had a 103-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 28, 2010, our coal stockpile at Plant Scherer contained a 62-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 – Clean Air Act."

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 Operating Company to operate these plants, including nuclear fuel procurement. Southern Nuclear Operating Company 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 and Hartwell. 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 MMbtus 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. Our leases expire in 2013, with options to renew for a total of 8.5 years. We also have fair market value purchase options at specified dates, including 2013 and the end of lease renewal terms. We treat these transactions as capital leases for financial reporting purposes. (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 Operating Company as the operator of Plants Hatch and Vogtle, pursuant to the Nuclear Operating Agreement between Georgia Power and Southern Nuclear Operating Company, 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 over a 15-year term. Delivery commenced May 15, 2000.

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 treat 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. RESERVED

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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 2009, have 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)				
	2009	2008	2007	2006	2005
STATEMENTS OF REVENUES AND EXPENSES DATA					
Operating revenues:					
Sales to Members	**$ 1,144,012**	$ 1,237,649	$ 1,149,657	$ 1,127,423	$ 1,136,463
Sales to non-Members	**1,249**	1,111	1,585	1,456	33,060
Total operating revenues	**1,145,261**	1,238,760	1,151,242	1,128,879	1,169,523
Operating expenses:					
Fuel	**360,412**	466,205	415,125	374,144	365,073
Production	**285,812**	278,981	246,675	254,658	251,830
Purchased power	**123,105**	160,133	155,005	179,129	255,616
Depreciation and amortization	**133,707**	119,540	131,434	156,829	152,556
Accretion	**18,261**	17,149	16,169	17,351	16,123
Other	**(158)**	(327)	(394)	(39,529)	(83,098)
Total operating expenses	**921,139**	1,041,681	964,014	942,582	958,100
Operating margin	**224,122**	197,079	187,228	186,297	211,423
Other income, net	**42,728**	43,381	54,854	51,414	26,776
Net interest charges	**(240,460)**	(221,201)	(223,021)	(219,510)	(220,546)
Net margin	**$ 26,390**	$ 19,259	$ 19,061	$ 18,201	$ 17,653
BALANCE SHEET DATA					
Electric plant, net:					
In service	**$ 3,557,723**	$ 3,152,911	$ 3,161,954	$ 3,274,080	$ 3,427,101
Nuclear fuel, at amortized cost	**215,949**	179,020	130,138	119,076	94,159
Construction work in progress	**626,824**	307,464	189,102	68,145	26,721
Total electric plant	**$ 4,400,496**	$ 3,639,395	$ 3,481,194	$ 3,461,301	$ 3,547,981
Total assets	**$ 6,370,234**	$ 5,044,452	$ 4,937,320	$ 4,901,745	$ 4,826,916
Capitalization:					
Long-term debt	**$ 4,267,706**	$ 3,361,463	$ 3,409,038	$ 3,402,094	$ 3,238,648
Obligations under capital leases	**239,461**	264,107	286,729	313,821	332,434
Obligations under Rocky Mountain transactions	**115,641**	108,219	101,272	94,772	88,689
Patronage capital and membership fees	**562,219**	535,829	516,570	497,509	479,308
Accumulated other comprehensive loss	**(1,253)**	(1,348)	(32,691)	(28,988)	(35,498)
Subtotal	**5,183,774**	4,268,270	4,280,918	4,279,208	4,103,581
Less: long-term debt and capital leases due within one year	**(119,241)**	(110,647)	(143,400)	(234,621)	(217,743)
Total capitalization	**$ 5,064,533**	$ 4,157,623	$ 4,137,518	$ 4,044,587	$ 3,885,838
Property additions	**$ 627,148**	$ 353,831	$ 194,739	$ 134,518	$ 69,744
OTHER DATA					
Energy supply (megawatt-hours):					
Generated	**19,699,706**	21,906,888	21,577,805	21,272,913	20,962,600
Purchased	**779,108**	1,755,225	1,593,864	2,108,654	3,812,809
Available for sale	**20,478,814**	23,662,113	23,171,669	23,381,567	24,775,409
Member revenues per kWh sold	**5.67¢**	5.30¢	5.04¢	4.90¢	4.79¢

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, substantially all 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.

Future Capital Requirements

Over the last several years, we have focused our efforts on developing a menu of generation options that offers members more ownership and control over their generation resources (through us) in order to help mitigate reliance on third-party contracts. In furtherance of these efforts, we have taken the following actions:

- We and the other co-owners of Plant Vogtle agreed to develop two additional nuclear units at the Plant Vogtle site, with each co-owner maintaining the same percentage ownership in the two new units as they have in the existing units. Our estimated total cost for our 30% interest in the two new units, including the allowance for funds used during construction, is approximately $4.2 billion, with planned commercial operation dates of 2016 and 2017.
- We are pursuing development of one 100 megawatt biomass-fueled generating plant. The plant is planned for commercial operation in 2014. We have acquired a site for this facility and are conducting preliminary engineering work and environmental analyses. Our estimated cost to construct this facility is $477 million, including allowance for funds used during construction.
- We are pursuing the development of one natural gas-fired 605 megawatt combined cycle facility with a target completion date of 2015. We are in the process of evaluating sites and plan to begin our preliminary engineering work and environmental analyses later this year. Our estimated cost to construct this facility is approximately $750 million, including allowance for funds used during construction.
- We and our members are currently evaluating additional specific gas-fired combustion turbine plants and combined cycle plants. Decisions regarding these plants are expected to be made over a two to three year period beginning as early as 2010.

In addition, we forecast that expenditures required for existing generating facilities will be approximately $800 million through 2012. These expenditures include normal additions and replacements to plant in-service and projects to maintain and achieve compliance with current and anticipated environmental requirements. Importantly, this forecast does not include additional capital expenditures or increased operational expenses for Plants Wansley and Scherer due to climate change legislation and regulation which is likely to be enacted or adopted in the future.

2009 Financial Results

Despite general 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 2009 were sufficient to recover all of our costs and to satisfy all of our debt service obligations and financial covenants, including the annual margin required to meet the margins for interest ratio rate covenant under the indenture. Specifically, we recorded a net margin of $26.4 million in 2009, which exceeded the required margins for interest ratio of 1.10. We believe that it is important to improve our margin coverage in light of current financial market conditions and a period of increased capital requirements, as noted above. Consequently, for the first time since our margins for interest ratio rate covenant was instituted in 1997, we are targeting higher margins than what would otherwise be necessary to meet the minimum required margins for interest ratio of 1.10 under the indenture. For 2009, we collected revenues sufficient to achieve a margins for interest ratio of 1.12, effectively increasing our annual margin target by 20%. In this regard, we recorded net margins of $26.4 million in 2009 as compared to net margins of $19.3 million for 2008. For 2010, we are targeting a margins for interest ratio of 1.14. As our generation construction program evolves, our board of directors will continue to evaluate the level of margin coverage 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 financial attributes that contributes to our competitive standing. In this regard, we maintained a strong liquidity position despite the disruption in the global financial markets in 2008 and strengthened our liquidity position throughout 2009 as financial market conditions became more favorable. At December 31, 2009, we had $1.3 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 a commercial paper program.

In 2009, in addition to using our liquidity to finance new generation projects, we issued $274 million of commercial paper to finance two acquisitions and refinance debt we assumed in conjunction with one of these acquisitions. In May we acquired the Hawk Road Energy Facility (a 500 megawatt peaking facility in Heard County, Georgia) and in October we acquired the Hartwell Energy Facility (a 300 megawatt oil and gas-fired peaking facility in Hart County, Georgia). As a result, we believe that our liquidity management program not only provides us with the ability to meet our financial obligations, but also provides us with a significant competitive advantage that will contribute to our ability to meet the future energy needs of our members in a cost-effective manner.

Outlook for 2010

We will 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 must be addressed, including:

- Continued ability to access financial markets to support our significant future capital requirements;
- General economic conditions in the U.S. and their impact on our members and their consumers;
- Managing the effects of potential environmental legislation and regulation regarding carbon dioxide and other emissions, particularly on Plants Wansley and Scherer; and
- Fuel cost volatility, including related transportation costs.

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 way through these risks, we intend to keep doing what we have done so successfully for the last 36 years, including, among other things:

- Maintaining a balanced diversity of generating resources – primarily nuclear, coal, natural gas and hydro.
- Working with our members to evaluate new resources, including renewables where feasible, to

be developed and owned by us to help meet our members' power supply requirements.

- Maintaining a strong liquidity position to fulfill our current obligations and to finance future capital expenditures.

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 $562 million in patronage capital and membership fees as of December 31, 2009. Our equity ratio, calculated as patronage capital and membership fees divided by total capitalization and long-term debt due within one year, was 10.8% at December 31, 2009 and 12.6% at December 31, 2008.

Patronage capital constitutes our principal equity. Any distributions of patronage capital is subject to the discretion of our board of directors. However, under the 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 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 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 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.

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 our 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 during the period April through December of the following year.

In 2008 and 2007, we achieved a margins for interest ratio of 1.10. However, to enhance margin coverage during the period of generation facility construction, our board of directors approved a budget for 2009 to achieve a 1.12 margins for interest ratio (above the minimum 1.10 required by the indenture). As a result, we achieved a margins for interest ratio of 1.12 in 2009. Our board of directors approved a budget for 2010 to achieve a 1.14 margins for interest ratio. As our construction program evolves, our board of directors will continue to evaluate the level of margin coverage and may choose to further increase, or decrease, the margins for interest ratio in the future.

Under the 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 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's (FASB) authoritative guidance issued regarding Accounting for the Effects of Certain Types of Regulation. 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, 2009, our regulatory assets and liabilities totaled $358 million and $109 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 the Effects of Certain Types of Regulation, 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 value.

New Accounting Pronouncements

In September 2009, we adopted the FASB Codification and the Hierarchy of Generally Accepted Accounting Principles (Codification). The Codification creates a two-level GAAP hierarchy – authoritative and non-authoritative – and establishes the Codification as the sole source of authoritative GAAP for non-governmental entities, except for rules and interpretive releases issued by the SEC. The Codification had no impact on our results of operations, cash flows or financial condition.

Effective January 1, 2009, we adopted FASB authoritative guidance issued regarding Disclosures about Derivative Instruments and Hedging Activities. The standard is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures that reflect the effect of these activities on an entity's financial position, financial performance, and cash flows. For a discussion of the effect of derivative instruments and hedging activities on our results of operations, cash flows and financial condition, see Note 2 in Notes to Consolidated Financial Statements.

In November 2007, the FASB issued a one-year deferral for the implementation of Fair Value Measurements for non-financial assets and non-financial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The deferral was applicable for asset retirement obligations measured at fair value upon initial recognition under Accounting for Asset Retirement Obligations, or upon a remeasurement event. We adopted Fair Value Measurements for non-financial assets and non-financial liabilities effective January 1, 2009 with no material effect on our results of operations, cash flows or financial condition.

Effective June 30, 2009, we adopted FASB standard Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly. The standard emphasizes that even if there has been a significant decrease in the volume and level of activity for the asset or liability and regardless of the valuation technique and inputs used, the objective for the fair value measurement is unchanged from what it would be if markets were operating at normal activity levels or transactions were orderly; that is, to determine the current exit price. The standard sets forth additional factors that should be considered to determine whether there has been a significant decrease in the volume and level of activity when compared with normal market activity. The reporting entity should evaluate the significance and relevance of the factors to determine whether, based on the weight of evidence, there has been a significant decrease in activity and volume. The standard indicates that if an entity determines that either the volume or level of activity for an asset or liability has significantly decreased (from normal conditions for that asset or liability) or price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The standard further notes that a fair value measurement should include a risk adjustment to reflect the amount market participants would demand because of the risk (uncertainty) in the cash flows.

This standard also requires a reporting entity to make additional disclosures in interim and annual periods. Revisions resulting from a change in valuation techniques or their application are accounted for as a change in accounting estimate. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective June 30, 2009, we adopted FASB authoritative guidance Interim Disclosures about Fair Value of Financial Instruments. The standard requires disclosures about the fair value of financial instruments in interim and annual financial statements. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective June 30, 2009, we adopted FASB standard Subsequent Events. The standard establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires management to evaluate events or transactions that may occur for potential recognition of disclosure in the financial statements, the circumstances under which events or transactions occurring after the balance sheet date should be recognized and events or transactions that should be disclosed that occur after the balance sheet date. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective January 1, 2010, we adopted FASB standard for Accounting for Transfers of Financial Assets – an amendment of Accounting for Transfers for Servicing of Financial Assets and Extinguishments of Liabilities. The standard requires improved disclosures about transfers of financial assets and removes the exception from applying Consolidation of Variable Interest Entities to qualifying special purpose entities. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective January 1, 2010, we adopted FASB standard Amendments to Consolidation of Variable Interest Entities. The standard provides new consolidation guidance for variable interest entities and requires a company to assess the determination of the primary beneficiary of a variable interest entity based on whether the company has the power to direct matters that most significantly impact the activities of the entity, and the obligation to absorb losses or the right to receive benefits of the entity. The standard also requires ongoing reassessments of whether a company is the primary beneficiary of a variable interest entity. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

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 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 7.6% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and increased 7.7% for the year ended December 31, 2008 compared to the year ended December 31, 2007. The components of member revenues were as follows:

	(dollars in thousands)		
	2009	2008	2007
Capacity revenues	**$ 641,713**	$ 591,546	$ 559,873
Energy revenues	**502,299**	646,103	589,784
Total	**$ 1,144,012**	$ 1,237,649	$ 1,149,657

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 8.5% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and increased 5.7% for the year ended December 31, 2008 compared to the year ended December 31, 2007. The increase in capacity revenues in 2009 compared to 2008 is primarily due to higher interest expense on long-term debt relating to environmental expenditures for existing coal-fired facilities that have now been placed in service and to an increase in the margins for interest ratio to 1.12 in 2009 compared to the margins for interest ratio of 1.10 in 2008. The increase in capacity revenues in 2008 as compared to 2007 resulted from higher collections from members due to increases in fixed production expenses resulting from (1) the $22.7 million reversal of the Monroe County property tax reserve in 2007 due to a favorable settlement (which lowered capacity revenue collections in 2007); there was no corresponding reversal in 2008, (2) an increase in staffing at Plants Hatch and Vogtle and (3) an increase in administrative and general expenses. Also, lower investment income from cash and temporary cash investments in the amount of $12.7 million in 2008 as compared to 2007 contributed to an increase in capacity collections from members in 2008. The increase in capacity revenues associated with increased production expenses and decreased investment income was offset somewhat by a full year of Plant Vogtle depreciation deferral in the amount of $28.6 million for 2008 as compared to a half year deferral in 2007 in the amount of $14.3 million. For further discussion regarding depreciation and amortization, see "– *Operating Expenses*"; for further discussions regarding investment income, see "– *Other Income*"; and see Note 12 of Notes to Consolidated Financial Statements for further information regarding the Monroe County property tax litigation reserve reversal.

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 22.3% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and increased 9.5% for the year ended December 31, 2008 compared to the year ended December 31, 2007. For 2009 compared to 2008, our average energy revenue per megawatt-hour from sales to our members was 10.3% lower in 2009 as compared to 2008. The decrease in energy revenues was primarily due to the pass-through to our members of lower fuel costs (primarily due to lower levels of coal-fired generation) and lower purchased power energy costs (primarily due to the lower volume of purchased megawatt-hours). In addition, natural gas-fired generation costs decreased due to a substantial drop in market prices for natural gas. For a discussion of fuel costs and purchased power costs, see "– *Operating Expenses.*" The increase in energy revenues for 2008 as compared to 2007 was primarily due to the pass-through of higher fuel costs associated with increased coal-fired generation at Plants Scherer and Wansley.

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

	(in thousands) Kilowatt-hours	Cents per Kilowatt-hour
2009	**20,191,657**	**5.67**
2008	23,308,911	5.31
2007	22,815,174	5.04

For the year ended December 31, 2009 compared to the year ended December 31, 2008, kilowatt-hour sales to members decreased 13.4% and for the year ended December 31, 2008 as compared to the year ended December 31, 2007, kilowatt-hour sales to members increased 2.2%. The average revenue per kilowatt-hour from sales to members increased 6.7% for 2009 compared to 2008 and increased 5.4% for 2008 compared to 2007. Decreases in kilowatt-hours of generation and kilowatt-hours of purchased power were the reasons for decreased kilowatt-hours sold to members in 2009. Conversely, increases in kilowatt-hours of generation and kilowatt-hours of purchased power were the reasons for increased kilowatt-hours sold to members in 2008. For further discussions 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 decreased 10.3% for the year ended December 31, 2009 as compared to the year ended December 31, 2008 and increased 7.2% for the year ended December 31, 2008 compared to the year ended December 31, 2007. The decrease in average energy revenues per kilowatt-hour in 2009 compared to 2008 is primarily due to the pass-through of lower fuel costs and lower purchased power energy costs. The increase in average revenues per kilowatt-hour in 2008 compared to 2007 is primarily due to the pass-through of higher fuel costs. For further discussion regarding fuel costs and purchased power costs, see "– *Operating Expenses*."

Operating Expenses

Our operating expenses decreased 11.6% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and were 8.0% higher for the year ended December 31, 2008 compared to the year ended December 31, 2007. The decrease in 2009 as compared to 2008 was primarily due to lower fuel costs and lower purchased power costs, offset somewhat by an increase in depreciation expense. The increase in 2008 as compared to 2007 was primarily due to higher fuel and production costs, offset somewhat by decreases in deprecation and amortization and in accretion expenses.

Total fuel costs decreased 22.7% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and increased 12.3% for the year ended December 31, 2008 as compared to the year ended December 31, 2007 while total generation decreased 10.1% and increased 2.0% for the years ended December 31, 2009 and 2008, respectively. Average fuel cost per kilowatt-hour decreased 14.0% in 2009 compared to 2008 and increased 10.1% in 2008 compared to 2007. For 2009, the decrease in total fuel costs resulted primarily from lower coal-fired generation at Plants Scherer and Wansley. In addition, fuel costs at the natural gas-fired Chattahoochee energy facility decreased as well due to substantially lower market prices for natural gas. The 2009 decrease in average fuel costs resulted primarily from a 26.7% decrease in coal-fired generation at Plants Scherer and Wansley due to increased scheduled outage time in 2009 compared to 2008. Coal-fired generation has a higher average cost per kilowatt-hour of generation than nuclear generation. Natural gas-fired generation at the Chattahoochee energy facility increased 54.9%, or 779,000 megawatt-hours in 2009, primarily as a result of a substantial decline in the price of natural gas; the average fuel cost per megawatt-hour of natural gas-fired generation at Chattahoochee decreased 55.1% from levels a year ago. The increase in total and average fuel costs for 2008 as compared to 2007 resulted primarily from an 8.4% increase in higher cost coal-fired generation at Plants Scherer and Wansley.

Production expenses increased 2.4% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and increased 12.5% for the year ended December 31, 2008 as compared to the year ended December 31, 2007. For 2008 as compared to 2007, the increase in production expenses resulted primarily from (1) the $22.7 million reversal of the Monroe County property tax reserve in 2007 due to a favorable settlement; there was no corresponding reversal in 2008, (2) increase staffing at Plants Hatch and Vogtle in response to new fitness for duty regulations impacting operations, maintenance and security departments at nuclear facilities and (3) increase in administrative and general expenses partly due to increased staffing levels and higher wages, payroll taxes and health benefits. The increase in administrative and general expenses was also partly due to a carbon capture research project administered through the Electric Power Research Institute. For further information regarding the reversal of the Monroe County property tax litigation reserve due to a favorable ruling from the Georgia Supreme Court, see Note 12 of Notes to Consolidated Financial Statements.

Purchased power costs decreased 23.1% for the year ended December 31, 2009 as compared to the year ended December 31, 2008 and increased 3.3% for the year ended December 31, 2008 compared to the year ended December 31, 2007 as follows:

	(dollars in thousands)		
	2009	2008	2007
Capacity costs	**$ 40,002**	$ 43,542	$ 41,437
Energy costs	**83,103**	116,591	113,568
Total	**$ 123,105**	$ 160,133	$ 155,005

The decrease in purchased power capacity costs for the year ended December 31, 2009 compared to the same period of 2008 was primarily as a result of our acquisition of the Hartwell Energy Facility in October 2009. As part of the acquisition, we acquired an existing power purchase agreement we had with the former owners of the Hartwell Energy Facility. Our acquisition of the Hartwell Energy Facility will further decrease our purchased power capacity and energy costs in future periods due to the addition of the new generating asset; however, we are now responsible for all expenses related to the operation and maintenance of the facility. See Note 5 and Note 13 of Notes to Consolidated Financial Statements for more information. The increase in purchased power capacity costs for the year ended December 31, 2008 as compared to the year ended December 31, 2007 was primarily due to an increase in the cost of services provided by Georgia System Operations under various agreements with us.

Purchased power energy costs decreased 28.7% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and increased 2.7% for the year ended December 31, 2008 compared to the year ended December 31, 2007. Purchased kilowatt-hours decreased 55.6% in 2009 compared to 2008 and increased 10.1% for 2008 compared to 2007. The average cost of purchased power energy per kilowatt-hour increased 60.6% in 2009 compared to 2008 and decreased 6.8% in 2008 compared to 2007. For the period ending December 31, 2009 compared to the same period of 2008, changes in purchased power energy costs, volume of kilowatt-hours acquired and average cost per kilowatt-hour were affected by the following items: (i) reduced purchased power energy costs from the lower volume of purchased kilowatt-hours and the increase in the cost per kilowatt-hour purchased were primarily due to the expiration of the Morgan Stanley purchased power agreement effective December 31, 2008, (ii) a lower average price per kilowatt-hour realized under our energy replacement program which replaces power from our owned generation facilities with lower price spot market purchased power energy, and (iii) realized losses incurred in 2009 for natural gas swap agreements we utilized to manage exposure to fluctuations in the market price of natural gas. The realized losses related to the natural gas swaps were somewhat offset the reduction in purchased power energy costs discussed in (i) and (ii) above. The decrease in the cost per kilowatt-hour of purchased power energy in 2008 as compared to 2007 was primarily due to increased kilowatt-hours acquired under our energy replacement program and by an increase in kilowatt-hours acquired under a purchased power agreement with Morgan Stanley which expired December 31, 2008. This increase was offset somewhat by reduced purchases of higher priced kilowatt-hours under a purchased power agreement with former owners of the Hartwell Energy Facility.

Purchased power expenses for the years 2007 through 2009 include the cost of capacity and energy purchases under various long-term power purchase agreements. Our capacity and energy expenses under these agreements amounted to approximately $26 million in 2009, $84 million in 2008 and

$89 million in 2007. For a discussion of the power purchase agreements, see Note 9 of Notes to Consolidated Financial Statements.

Depreciation and amortization expense increased 11.9% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and decreased 9.0% for the year ended December 31, 2008 as compared to the year ended December 31, 2007. The increase in depreciation and amortization in 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 the Hawk Road Energy Facility acquired in 2009 contributed to the increase. For information regarding the Hawk Road Energy Facility, see Note 13 of Notes to Consolidated Financial Statements. Depreciation and amortization expense decreased in 2008 compared to 2007 primarily due to the deferral of $28.6 million in depreciation and amortization expense at Plant Vogtle in 2008 compared to a $14.3 million deferral of depreciation and amortization expense in 2007. In 2007, Georgia Power, as agents for the co-owners, filed an application with the Nuclear Regulatory Commission to extend the licenses for Vogtle Unit No. 1 and Unit No. 2 for an additional 20 years. Effective July 1, 2007, under the provisions of Accounting for the Effects of Certain Types of Regulation, we began deferring the difference between Plant Vogtle depreciation expense based on the current 40-year operating license versus depreciation expense based on the applied for 20-year license extension. On June 3, 2009, the Nuclear Regulatory Commission granted 20 year license extensions for Vogtle Unit No. 1 and Unit No. 2. Amortization of the deferred amount totaling approximately $54.9 million at May 31, 2009 to depreciation expense over the extended license period began in June 2009.

Accretion expense totaled $18.3 million for the year ended December 31, 2009, $17.1 million for the year ended December 31, 2008 and $16.2 million for the year ended December 31, 2007. The accretion expense recognized under Accounting for Asset Retirement Obligations, primarily relates to our nuclear generation facilities.

Other Income

Investment income increased 4.4% for the year ended December 31, 2009 compared to the year ended December 31, 2008 and decreased 29.4% for the year ended December 31, 2008 compared to the year ended December 31, 2007. The increase in investment income for 2009 as compared to 2008 resulted primarily from increased earnings on the Rural Utilities Service Cushion of Credit Account due to higher balances in this account. The higher balances in this account resulted from our power bill prepayment program. See Note 1 of Notes to Consolidated Financial Statements for further discussion. Additionally, a decrease in interest earnings on cash and cash equivalent instruments partly due to lower market interest rates on those investments offset somewhat by higher average investment balances in 2009 compared to 2008 contributed to the overall slight increase in investment income in 2009 as compared to 2008. The decrease in investment income for 2008 as compared to 2007 resulted primarily from realized investment losses sustained in the decommissioning trust fund. In addition, a decrease of $13.2 million in earnings from cash and temporary cash investments as a result of lower average investment balances and lower interest rates on those investments contributed to the decrease in 2008 versus 2007.

The income (loss) from investments in our external and internal decommissioning funds for 2009, 2008 and 2007 totaled ($0.7) million, ($32.2) million and $18.9 million, respectively. As noted above, for nuclear decommissioning, we record a regulatory asset or liability for the timing difference in accretion expense recognized under Accounting for Asset Retirement Obligations, compared to the expense recovered for ratemaking purposes. The adjustments to investment income for these timing differences resulted in an increase to the regulatory asset of $18.0 million in 2009, $48.5 million in 2008 and an increase to the regulatory liability of $3.6 million in 2007. The increase to the regulatory asset in 2008 is primarily due to significant realized investment losses in the decommissioning trust fund.

In December 2009, Georgia Power provided us with revised asset retirement obligations studies associated with decommissioning Plants Hatch and Vogtle. The new studies resulted in a decrease in the estimated cost of decommissioning these nuclear plants. Notwithstanding the results of these revised studies, our management believes that any increase in cost estimates of decommissioning can be recovered in future rates.

See Note 1 of Notes to Consolidated Financial Statements for further discussion.

Interest Charges

Interest on long-term debt and capital leases increased by 12.6% for the year ended December 31, 2009 compared to the same period of 2008. This increase was primarily due to the issuance in February 2009 of $350 million in taxable fixed rate bonds.

Allowance for debt funds used during construction increased by 57.8% for 2009 compared to the same period of 2008 primarily due to construction expenditures for Plant Vogtle Units No. 3 and No. 4. The 76.1% increase in 2008 compared to 2007 in allowance for debt funds used during construction is primarily due an increase in construction work in progress for environmental compliance expenditures at coal-fired Plants Scherer and Wansley.

Other interest was higher for the year ended December 31, 2008 compared to the years ended December 2009 and 2007 primarily due to interest incurred on short-term borrowings during 2008.

Net Margin

Our net margin for the years ended December 31, 2009, 2008 and 2007 was $26.4 million, $19.3 million and $19.1 million, respectively. These amounts produced respective margins for interest ratio of 1.12, 1.10 and 1.10, each greater than or equal to the minimum required under the indenture. Our margin requirement is based on a ratio applied to interest charges. 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 $1.5 million for 2009 and $1.4 million each year in 2008 and 2007.

To continue to enhance our financial coverage during a period of generation facility construction, our board of directors approved a budget for 2010 to achieve margins for interest ratio of 1.14, above the minimum 1.10 ratio required by the 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 2009, we achieved a 1.12 margins for interest ratio which produced a net margin of $26.4 million. This caused a corresponding increase in patronage capital (our equity), bringing total patronage capital and membership fees to $562 million at December 31, 2009.

The minimum margins for interest ratio required under the indenture is 1.10. However, to enhance margin coverage during the period of generation facility construction, our board of directors approved the 1.12 margins for interest ratio for 2009 and approved a further increase to 1.14 for 2010. As our generation construction program evolves, our board of directors will continue to evaluate the level of margin coverage 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 2009, the majority of which relates to the generation facility construction, our equity to total capitalization ratio decreased from 12.6% at December 31, 2008 to 10.8% at December 31, 2009. While the absolute level of margins and thus patronage capital are increasing, our equity ratios will continue to decrease during the peak years of generation facility construction, at which point it is expected to begin increasing again.

Also in connection with our generation construction program, we strengthened our liquidity position by putting in place additional credit commitments totaling $575 million during 2009, in addition to renewing an existing $50 million credit facility. This contributed to a healthy liquidity position, with $1.3 billion of unrestricted available liquidity at December 31, 2009, including $579 million of cash.

Our total assets increased to $6.4 billion at December 31, 2009 from $5.0 billion at December 31, 2008. The majority of this increase relates to (i) an increase in total utility plant in connection with the construction of Plant Vogtle Units No. 3 and No. 4 and the acquisition of the Hawk Road Energy Facility and the Hartwell Energy Facility, and (ii) higher cash balances as a result of new debt financings related to the Vogtle construction and funds received under the member power bill prepayment program.

We maintained adequate access to capital throughout 2009, issuing more than $862 million of long-term debt in the capital markets (see "– *Financing Activities*"). We also issued commercial paper at historically low rates averaging less than 0.5%, which provided a low-cost source of short-term funding for the generation projects under construction as well as for the acquisition of the Hawk Road Energy Facility and the Hartwell Energy Facility.

There was a net increase in long-term debt of $906 million at December 31, 2009 compared to December 31, 2008. The significant net increase was due to the issuance of $750 million of first mortgage bonds to fund new generation construction, $101 million of new tax-exempt bonds to fund environmental compliance projects, and $114 million of funds advanced under Rural Utilities Service loans. The average interest rate on the $4.3 billion of long-term debt outstanding at December 31, 2009 was 5.4%.

Property additions totaled $627 million and were financed with a combination of funds from operations and short-term and long-term borrowings. The property additions related to purchases of nuclear fuel, normal additions and replacements to existing generation facilities, environmental control facilities being installed at the coal-fired generation facilities and construction of new generation facilities.

The three major rating agencies have all assigned investment grade credit ratings to us. See "– *Credit Rating Risk*" for our current credit ratings.

Liquidity and Sources of Capital

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 (one of our coal-fired facilities) and the construction of new generation facilities, 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-guaranteed funding for new generation facilities is uncertain and may be limited at any point in the future due to budgetary and political pressures faced by Congress. Also, over the next ten years the loan demand of electric cooperatives is projected to exceed Rural Utilities Service-guaranteed funding authorization levels unless there is an increase over current levels of funding. The President's budget for fiscal year 2011 proposes to reduce funding by almost 40% from 2010 levels and, in support of the President's commitment to reduce inefficient fossil-fuel subsidies, prohibit loans for new or existing fossil-fueled generation. The budget limits the use of electric loan funds to renewable energy, transmission, distribution and carbon-capture projects on generation facilities. 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-guaranteed 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. The types of equipment that will qualify for tax-exempt financing, however, are fewer than in the past due to changes in tax laws and regulations.

Therefore, any generation facilities that we may build 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, 2009, we had $1.3 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of $579 million of cash and cash equivalents and $727 million of unused and available committed short-term credit arrangements. Our liquidity position has increased significantly due to (i) higher cash balances related to the member power bill prepayment program and proceeds received from a first mortgage bond issuance in November 2009 and a tax-exempt bond issuance in December 2009, and (ii) an increase in available liquidity in connection with three new committed credit facilities that were put in place during 2009.

Net cash provided by operating activities was $409 million in 2009, and averaged $233 million for the three year period 2007 through 2009.

At December 31, 2009, we had $1.125 billion of committed credit arrangements comprised of six separate facilities as reflected in the table below:

Committed Short-Term Credit Facilities

(dollars in millions)

	Authorized Amount	Available 12/31/2009	Expiration Date
Unsecured Facilities:			
Commercial Paper Line of Credit	$ 475	$ 191	July 2012
CoBank Line of Credit	50	50	December 2010
CFC Line of Credit	50	50	October 2011
JPMorgan Chase Line of Credit(1)	150	36(2)	December 2012
Secured facilities:			
CoBank Line of Credit(1)	150	150	November 2012
CFC Line of Credit(1)	250	250	December 2013
Total	**$ 1,125**	**$ 727**	

(1) New facility put in place in 2009.

(2) $114 million of this facility is currently utilized as letter of credit support for variable rate pollution control revenue bonds.

We expect to renew these short-term credit facilities, as needed, prior to their respective expiration dates.

We have used or plan to use our short-term credit arrangements to provide temporary funding for (i) payments to Georgia Power related to the construction of Plant Vogtle Units No. 3 and No. 4, (ii) acquisition of the Hawk Road Energy Facility in May 2009 and the Hartwell Energy Facility in October 2009, and (iii) initial engineering and design work, and eventually construction, related to the Warren County biomass facility and a 605 megawatt combined cycle facility. For a discussion of the new generation projects under development, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4,*" "– *Biomass Plant*" and "– *Combined Cycle Plant*." For a discussion of the Hawk Road Energy Facility and Hartwell Energy Facility acquisitions, see Notes 13(a) and 13(b), respectively, of Notes to Consolidated Financial Statements. For a discussion of our plans regarding permanent financing of these generation facilities, see "– *Financing Activities*."

Several of our line of credit facilities contain a similar financial covenant that requires us to maintain minimum patronage capital levels. Currently, we are required to maintain minimum patronage capital of $525 million. As of December 31, 2009 our actual patronage capital was $562 million. An additional covenant contained in several of our credit facilities limits our secured indebtedness to $8.5 billion and unsecured indebtedness to $4.0 billion. At December 31, 2009, we had approximately $4.3 billion of secured indebtedness outstanding and $284 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 indenture.

Under the 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. We periodically assess our needs to determine the appropriate amount of commercial paper backup to maintain and currently have in place a $475 million committed backup credit facility provided by eight banks as shown in the table below:

Commercial Paper Credit Facility – Participant Banks	Commitment (dollars in millions)
Bank of America, N.A. – Administrative Agent	$ 75
SunTrust Bank	$ 75
The Bank of Tokyo – Mitsubishi UFJ, Ltd.	$ 60
CoBank, ACB	$ 60
JPMorgan Chase Bank, National Association	$ 60
National Rural Utilities Cooperative Finance Corporation	$ 60
Wachovia Bank, N.A. / Wells Fargo Bank, N.A.	$ 60
Goldman Sachs Bank USA	$ 25
Total	**$ 475**

Along with the lines of credit from CoBank, CFC and JPMorgan Chase Bank, funds may also be advanced under the backup line of credit supporting commercial paper for general working capital purposes. In addition, under certain of our committed lines of credit we have the ability to issue letters of credit totaling $450 million in the aggregate. However, any amounts related to issued letters of credit will reduce the amount available to draw as working capital under those facilities. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under the commercial paper backup line for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue.

Between projected cash on hand and the credit facilities currently in place, we believe we will have sufficient liquidity to fund our generation construction program and to cover normal operations through at least 2011. However, we may pursue additional credit facilities to further enhance our liquidity position during the peak years of new generation construction (2012 through 2014). The timing, size and term of any additional facilities will be influenced by many factors, including the ultimate size of the construction program, the timing of permanent financing for new generation facilities and overall market conditions.

In December 2008 we instituted a power bill prepayment program to provide for an additional source of liquidity. Under the program, 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. At December 31, 2009, we had received member advances totaling $210 million from fifteen members participating in the program. We began applying the advances against power bills in May 2009 and expect to continue doing so through September 2013, with the majority scheduled to be applied in 2010. An additional $30.5 million in member advances was received subsequent to December 31, 2009. This program had the effect of increasing our cash flows from operations by $196 million in 2009.

In addition to unrestricted available liquidity, we had $103 million of restricted liquidity at December 31, 2009, including (i) $81 million in restricted short-term investments pursuant to deposits made into a Rural Utilities Service Cushion of Credit Account, (ii) $22 million in restricted cash, including $11 million of tax-exempt refunding bond proceeds on deposit with our bond trustee and $11 million of proceeds from our issuance of clean renewable energy bonds on deposit with a bank. 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. We deposited an additional $40 million into the Cushion of Credit Account in January 2010, and we intend to apply all of the funds currently in the account against debt service payments due in 2010. The $11 million on deposit with our bond trustee was in connection with pollution control bonds issued in December 2009, the proceeds of which were used in January 2010 to refinance $11 of pollution control bond amortizing maturities. We anticipate that the $11 million of clean renewable energy bond proceeds will be drawn down over the next two years. See "– *Financing Activities*" for further discussion on these financings.

Liquidity Covenants. At December 31, 2009, 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 2009 and expect to have sufficient liquidity to meet this covenant in 2010.

Current Financial Market Conditions

We were able to weather the recent turmoil in the credit and financial markets without any material negative impacts. While the peak of the crisis occurred in 2008, the markets began recovering in 2009. Nonetheless, certain segments of the financial markets remain noticeably weaker than they were before the crisis, especially the commercial bank market (as it relates to the availability and cost of credit).

Despite the severe stress and disruption experienced in the credit and financial markets, and the diminished confidence in these markets and in the economy in general, during 2009 the markets rebounded significantly, with credit and liquidity from banks becoming more available and under better and longer terms. We were able to put in place three new multi-year credit facilities in 2009 totaling $550 million in the aggregate. In addition, the market for corporate debt has improved, credit spreads have tightened, and borrowing rates have trended lower. We successfully accessed the taxable bond markets in February 2009 and November 2009, issuing a total of $750 million at favorable fixed rates due in part to historically low Treasury rates. The commercial paper markets have improved as well, and we have been successfully issuing commercial paper at favorable short-term rates since the spring of 2009.

Obtaining favorable financing is important to our business due to, among other things, our significant capital needs related to (i) normal maintenance of, and compliance with environmental requirements and regulations at our existing generation facilities, and (ii) construction of new generation facilities requested by our members to support growth in their energy needs. See "– *Liquidity*" and "– *Financing Activities*" for additional information regarding our short-term and long-term financing needs and arrangements.

Financing Activities

Our Indenture. Our first mortgage debt is secured equally and ratably under the 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. Two of our recently acquired generating facilities, the Hawk Road Energy Facility and Hartwell Energy Facility, are currently owned by two of our wholly-owned subsidiaries and not directly by us. Consequently, these two generating facilities are not currently included in the mortgaged property; however, we anticipate they will become part of the mortgaged property in 2010.

To facilitate our financing plans, especially in light of the significant amount of financing required for new generation construction, we amended the indenture in February 2009, with the consent of a majority of the holders of indenture obligations outstanding, to (i) allow us to finance construction of generation and related facilities by issuing indenture obligations based on a percent of progress payments made under contracts for engineering, construction or procurement services that have been pledged under the indenture, and (ii) remove the restriction on short-term indebtedness (i.e., short-term indebtedness cannot exceed 15% of total capitalization) from the indenture. In connection with providing its consent to the indenture changes, the Rural Utilities Service required an amendment to our Amended and Restated Loan Contract with the Rural Utilities Service pursuant to which a less restrictive short-term indebtedness provision was incorporated. The new covenant provides that until December 31, 2014, our short-term indebtedness shall not exceed 30% of total utility plant, and thereafter it shall not exceed 15% of total capitalization unless the Rural Utilities Service has granted an extension of the higher amount.

Bond Financings. In February 2009, we issued $350 million of fixed rate first mortgage bonds. The bonds were issued for the purpose of financing a portion of the cost of construction of new generation facilities, to enhance existing generation facilities and to provide liquidity for general corporate purposes. In November 2009, we issued another $400 million of fixed rate first mortgage bonds for the purpose of financing a portion of constructing Plant Vogtle Units No. 3 and No. 4 (including redeeming commercial paper issued in connection with the construction of these new nuclear units) and to provide liquidity for general corporate purposes. All $750 million of these first mortgage bonds are secured under the indenture.

In December 2009, we issued $112 million of variable rate tax-exempt pollution control revenue bonds, including (i) $11 million to refinance principal maturing on January 1, 2010 under existing pollution control revenue bonds, and (ii) $101 million of new tax-exempt pollution control revenue bonds related to the installation of scrubbers at Plant Wansley and a mercury control project at Plant Scherer. This tax-exempt debt is secured under the indenture.

Also in December 2009, we issued $16 million of clean renewable energy bonds, at a very low fixed rate of interest, to finance a portion of the cost of an overhaul and upgrade project underway at our Rocky Mountain facility. The clean renewable energy bonds are secured under the indenture.

In 2009, we were awarded tax-exempt volume cap financing allocations from the State of Georgia in connection with an environmental compliance project currently underway at Plant Scherer (one of our coal-fired facilities) as well as for our proposed biomass facility. However, it is uncertain at this time what equipment at these projects may qualify for tax-exempt financing. We also received volume cap allocation in 2009 from the Internal Revenue Service to issue the new form of clean renewable energy bonds to fund a portion of our proposed biomass facility. The ultimate size and timing for future tax-exempt financings or issuance of new clean renewable energy bonds in connection with these volume cap allocations cannot be determined at this time.

We have a program in place under which we are refinancing, on a continued tax-exempt basis, the annual principal maturities of pollution control bonds originally issued on our behalf by a county development authority. 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 $278 million under this program, including $11 million of principal that matured in January 2010 (of which Georgia Transmission assumed an obligation to pay $1.8 million, as discussed below). We have board approval to continue this refinancing program covering an additional $20 million of pollution control bond principal maturing through January 2012.

Under an indemnity agreement executed in connection with Georgia Transmission's assumption of pollution control bond indebtedness as part of our 1997 corporate restructuring (see "– *Off-Balance Sheet Arrangements – Georgia Transmission Debt Assumption*"), and additional indemnity agreements executed in connection with Georgia Transmission's assumption of pollution control bond refunding indebtedness in 2006, 2007, 2008 and 2009, Georgia Transmission is entitled to participate in any refinancing or prepayment of its assumed pollution control bond debt by agreeing to assume a portion of the refunding indebtedness. As such, Georgia Transmission elected to participate in our refinancing of the January 2010 maturity, and we anticipate that Georgia Transmission will continue to participate in the refinancing of the pollution control bond principal maturing through 2012 as discussed above.

Rural Utilities Service-Guaranteed Loans. We currently have three approved Rural Utilities Service-guaranteed loans, funded through the Federal Financing Bank, totaling $844 million that are in various stages of being drawn down, with $683 million remaining to be advanced. One of these loans, totaling $310 million, was approved in August 2009 and relates to general improvements at existing facilities and environmental projects at Plants Scherer and Wansley.

We have three loan applications pending with the Rural Utilities Service that we anticipate action on in 2010 or 2011, including two applications related to the Hawk Road Energy Facility acquisition and the Hartwell Energy Facility acquisition, respectively, which we anticipate they will act on in 2010, and a loan application related to the Warren County biomass facility that we anticipate they will act on in 2011.

Although the President's budget proposal for 2011 would prohibit Rural Utilities Service funding for construction of fossil-fueled generation facilities, we anticipate submitting an additional loan application related to our planned natural gas-fired combined cycle facility in the second quarter of 2010. Further, should members subscribe to any additional natural-gas fired combined cycle or combustion turbine facilities, we anticipate filing loan applications for these facilities as well, to the extent Rural Utilities Service regulations in place at that time allow us to do so. See "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources" for a discussion of our participation in new generation facilities. 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 the indenture.

Department of Energy-Guaranteed Loans. In connection with our participation in the two new nuclear units proposed at Plant Vogtle, we have been in negotiations with the Department of Energy to participate in a loan guarantee program to provide partial funding for our $4.2 billion share of the estimated cost to construct these nuclear units. 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 the commercialization of innovative technologies to reduce air pollutants, including greenhouse gases. The loan structure would entail a loan funded through the Federal Financing Bank carrying a federal loan guarantee provided by the Department of Energy, with the debt secured under our indenture.

On February 16, 2010, the Department of Energy offered us a conditional term sheet that sets forth the general terms of the loan and offered a guarantee that would target 70% of eligible project costs, not to exceed $3.057 billion. We have until May 17, 2010 to accept the terms of the conditional term sheet. We will work with the Department of Energy to finalize the loan guarantee. However, final approval and issuance of a loan guarantee by the Department of Energy is subject to receipt of the combined construction permits and operating licenses for Plant Vogtle Units No. 3 and No. 4 from the Nuclear Regulatory Commission (a decision is currently anticipated in fourth quarter 2011), 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.

For any Plant Vogtle project costs not funded by the Department of Energy, we plan to issue taxable bonds and tax-exempt bonds for any equipment that may qualify for tax-exempt financing. Of the $1.2 billion of estimated project costs that will not be financed by the Department of Energy, we have already financed $400 million through the issuance of first mortgage bonds in November 2009, and we have plans to issue an additional approximately $400 million of first mortgage bonds for this purpose by the end 2010.

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 expenditure forecasts for 2010 through 2012. 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)

	2010	2011	2012	Total
Future Generation[2]	$ 524	$ 735	$ 859	$ 2,118
Existing Generation[3]	79	83	93	255
Environmental Compliance[4]	116	185	240	541
Nuclear Fuel	110	121	131	362
General Plant	6	6	1	13
Total	$ 835	$ 1,130	$ 1,324	$ 3,289

(1) Includes allowance for funds used during construction

(2) Construction of Vogtle Units No. 3 & No. 4, the Warren County biomass facility and a 605 megawatt combined cycle facility

(3) Normal additions and replacements to plant in-service

(4) Pollution control equipment being installed at Plant Scherer

In addition to the amounts reflected in the table above, we expect to spend approximately $2.4 billion by 2017 to complete construction of Plant Vogtle Units No. 3 and No. 4, the Warren County wood-burning biomass facility and the gas-fired combined cycle facility. For information about steps we have taken to procure financing for these projects, see "– *Financing Activities.*"

We have identified and are evaluating other generation resource development opportunities that we could pursue to meet our members' future energy needs, including certain quantities of gas-fired combustion turbines and combined cycle plants. These options, which are subject to future member subscription for specific projects, are not included in the capital expenditures table above (see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources"). Additional projects that we may ultimately construct, if any, as well as the cost of construction, are not known at this time.

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 already completed include a selective catalytic reduction system and a flue gas desulfurization project at Plant Wansley, and a mercury removal project at Plant Scherer.

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. To complete these projects, we expect to spend an additional approximately $103 million beyond what is 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."

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.

Contractual Obligations. The table below reflects, as of December 31, 2009, our contractual obligations for the periods indicated.

Contractual Obligations
(dollars in millions)

	2010	2011-2012	2013-2014	Beyond 2014	Total
Long-Term Debt:					
Principal	$ 89	$ 191	$ 185	$ 3,803	$ 4,268
Interest[1]	231	450	442	2,919	4,042
Capital Leases[2]	44	88	66	133	331
Operating Leases	5	12	12	20	49
Rocky Mtn.Lease Transactions[3]	–	–	–	372	372
Chattahoochee O&M Agmts.	21	43	46	93	203
Asset Retirement Obligations[4]	–	–	–	2,169	2,169
Member Advances	186	13	6	–	205
Total	**$ 576**	**$ 797**	**$ 757**	**$ 9,509**	**$ 11,639**

(1) Includes interest expense related to variable rate debt. Future variable rates are based on a forward SIFMA interest rate curve as of March 2010.

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

(3) 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.*"

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

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	A3	A
Issuer rating	n/r[2]	Baa1	n/r[2]
Rating outlook	Stable	Negative	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, 2009, our maximum potential collateral requirements were as follows:

At senior secured rating levels:

- a total of approximately $57 million at a senior secured level of BBB-/Baa3,
- a total of approximately $187 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured rating levels:

- a total of approximately $400,000 at a senior unsecured or issuer rating level of BBB-/Baa3,
- a total of approximately $8 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 put our 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 December 31, 2009, the total obligation assumed by Georgia Transmission relating to outstanding pollution control bond principal was $94 million. Georgia Transmission's estimated payments of principal and interest in 2010 pursuant to this assumed obligation are approximately $7 million.

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 2009, the amount of the rental payments under the facility subleases and facility leases each totaled $57 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 AAA 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 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 instrumentality 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 ($116 million at December 31, 2009). 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 $122 million at December 31, 2009.

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 A3 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 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 ($116 million at December 31, 2009 and $108 million at December 31, 2008). 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, 2009, both the Deposit on Rocky Mountain transactions and Obligation under Rocky Mountain transactions would have been higher by $711 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. (See ''BUSINESS – OGLETHORPE POWER CORPORATION – Electric Rates'' for further discussion of our rate structure.)

We have a risk management committee that provides general oversight over all risk management activities, including commodity trading, fuels management, insurance procurement, debt management and investment portfolio management. 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 committee has implemented comprehensive risk management policies to manage and monitor credit and market price 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, and hedge positions. 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, 2009, we were exposed to the risk of changes in interest rates related to our $860 million of variable rate debt, including $284 million of commercial paper outstanding (which typically has maturities of between 30 and 60 days) and $565 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 2010 through April 2012). At December 31, 2009, the weighted average interest rate on this variable rate debt was 2.2%. If, within the next twelve months, 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 $7 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, 2009, we had 19% 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, auction rate 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.

Due to the significant amount of new long-term debt we anticipate incurring in connection with our new generation projects (including the two facilities acquired in 2009 as well as the projects under construction), we will have increased risk associated with interest rates in general. If we are in a rising interest rate environment at the point we are issuing new debt for these projects (whether it be Federal Financing Bank debt or publically issued bonds), the higher level of interest rates will increase our costs.

At any point in time, we may analyze and consider using various types of derivative products (including swaps, caps, floors and collars) to help manage our interest rate risk, but do not currently have any in place.

Capital Leases

In December 1985, we sold and subsequently leased back from four purchasers our 60% undivided ownership interest in Scherer Unit No. 2. The capital leases provide that our rental payments vary to the extent of interest rate changes associated with the debt used by the lessors to finance their purchase of undivided ownership shares in the unit. The debt currently consists of $27 million in serial facility bonds due June 30, 2011 with a 6.97% fixed rate of interest.

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, 2009, the weighted average interest rate on the lease obligation was 6.02%.

Equity Price Risk

We maintain external trust funds (reflected as "Decommissioning 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.

Our nuclear decommissioning funds (external and internal combined) declined approximately 18% in value in 2008 but increased by 19% in 2009.

A 10% decline in the value of the internal and external funds' equity securities as of 2009 would result in a loss of value to the funds of approximately $16 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 98% of our remaining forecasted coal requirements for 2010 and fixed or capped prices for approximately 95% of our forecasted coal requirements in 2011.

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 four gas-fired generation facilities totaling 1,886 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 enter into natural gas swap arrangements to manage our exposure to fluctuations in the market price of natural gas. 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, 2009, we would have made a net payment of approximately $12.5 million. We have obtained our members' approval required by the New Business Model Member Agreement to continue to manage exposures to natural gas price risks for members that elect to receive such services. We are providing natural gas price risk management services to 15 of our members. Effective April 1 of each year, additional members may elect to receive these services. Members may elect to discontinue receiving these services at any time.

Changes in Risk Exposure

Our exposure to changes in interest rates, the price of equity securities we hold, and commodity prices have not changed materially from the previous reporting period. We are not aware of any facts or circumstances that would significantly impact these exposures in the near future; however, nonperformance by one of our hedge counterparties may increase our exposure to market volatility.

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, 2009, 2008 and 2007

	(dollars in thousands)		
	2009	2008	2007
Operating revenues:			
Sales to Members	**$ 1,144,012**	$ 1,237,649	$ 1,149,657
Sales to non-Members	**1,249**	1,111	1,585
Total operating revenues	**1,145,261**	1,238,760	1,151,242
Operating expenses:			
Fuel	**360,412**	466,205	415,125
Production	**285,812**	278,981	246,675
Purchased power	**123,105**	160,133	155,005
Depreciation and amortization	**133,707**	119,540	131,434
Accretion	**18,261**	17,149	16,169
Other	**(158)**	(327)	(394)
Total operating expenses	**921,139**	1,041,681	964,014
Operating margin	**224,122**	197,079	187,228
Other income:			
Investment income	**31,825**	30,483	43,157
Amortization of deferred gains	**5,660**	5,660	5,660
Allowance for equity funds used during construction	**2,394**	3,075	1,802
Other	**2,849**	4,163	4,235
Total other income	**42,728**	43,381	54,854
Interest charges:			
Interest on long-term debt and capital leases	**238,531**	211,793	212,003
Other interest	**2,212**	6,249	2,253
Allowance for debt funds used during construction	**(19,345)**	(12,259)	(6,962)
Amortization of debt discount and expense	**19,062**	15,418	15,727
Net interest charges	**240,460**	221,201	223,021
Net margin	**$ 26,390**	$ 19,259	$ 19,061

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2009 and 2008

	(dollars in thousands)	
	2009	2008
Assets		
Electric plant:		
In service	**$ 6,550,938**	$ 5,906,865
Less: Accumulated provision for depreciation	**(2,993,215)**	(2,753,954)
	3,557,723	3,152,911
Nuclear fuel, at amortized cost	**215,949**	179,020
Construction work in progress	**626,824**	307,464
Total electric plant	**4,400,496**	3,639,395
Investments and funds:		
Decommissioning fund	**239,746**	201,094
Deposit on Rocky Mountain transactions	**115,641**	108,219
Bond, reserve and construction funds	**3,982**	4,560
Investment in associated companies	**53,199**	43,441
Long-term investments	**87,129**	81,550
Other, at cost	**615**	391
Total investments and funds	**500,312**	439,255
Current assets:		
Cash and cash equivalents, at cost	**579,069**	167,659
Restricted cash, at cost	**22,405**	10,255
Restricted short-term investments	**80,590**	–
Receivables	**110,258**	116,679
Inventories, at average cost	**209,837**	175,350
Prepayments and other current assets	**9,393**	5,619
Total current assets	**1,011,552**	475,562
Deferred charges:		
Premium and loss on reacquired debt, being amortized	**122,847**	130,013
Deferred amortization of capital leases	**77,755**	85,612
Deferred debt expense, being amortized	**57,262**	41,905
Deferred outage costs, being amortized	**31,319**	27,137
Deferred tax assets	**24,000**	48,000
Deferred asset associated with retirement obligations	**31,413**	60,310
Deferred interest rate swap termination fees, being amortized	**29,296**	33,286
Deferred depreciation expense, being amortized	**54,056**	42,955
Other	**29,926**	21,022
Total deferred charges	**457,874**	490,240
Total assets	**$ 6,370,234**	$ 5,044,452

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2009 and 2008

	(dollars in thousands)	
	2009	2008
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 562,219**	$ 535,829
Accumulated other comprehensive deficit	**(1,253)**	(1,348)
	560,966	534,481
Long-term debt	**4,178,981**	3,278,856
Obligations under capital leases	**208,945**	236,067
Obligation under Rocky Mountain transactions	**115,641**	108,219
Total capitalization	**5,064,533**	4,157,623
Current liabilities:		
Long-term debt and capital leases due within one year	**119,241**	110,647
Short-term borrowings	**283,634**	140,000
Accounts payable	**24,184**	29,305
Accrued interest	**50,947**	34,539
Accrued and withheld taxes	**24,864**	18,827
Members' advances, current	**182,514**	–
Other current liabilities	**28,000**	28,081
Total current liabilities	**713,384**	361,399
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**31,062**	33,536
Net benefit of Rocky Mountain transactions, being amortized	**54,151**	57,336
Asset retirement obligations	**264,635**	281,458
Accumulated retirement costs for other obligations	**43,955**	49,675
Long-term contingent liability	**24,000**	48,000
Members' advances, non-current	**18,000**	5,000
Power sale agreement, being amortized	**86,211**	–
Other	**70,303**	50,425
Total deferred credits and other liabilities	**592,317**	525,430
Total equity and liabilities	**$ 6,370,234**	$ 5,044,452

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, 2009 and 2008

	(dollars in thousands)	
	2009	2008
Long-term debt:		
Mortgage notes payable to the Federal Financing Bank (FFB) at interest rates varying from 2.70% to 8.43% (average rate of 5.47% at December 31, 2009) due in quarterly installments through 2042	**$ 1,693,478**	$ 1,652,952
Mortgage notes payable to Rural Utilities Service (RUS) at an interest rate of 5% due in monthly installments through 2020	**8,635**	9,269
Mortgage bonds payable:		
• Series 2006		
Term Bonds, 5.53%, due 2031 through 2035	**300,000**	300,000
• Series 2007		
Term Bonds, 6.19%, due 2024 through 2031	**500,000**	500,000
• Series 2009A		
Term Bonds, 6.10%, due 2019	**349,740**	–
• Series 2009B		
Term Bonds, 5.95%, due 2039	**400,000**	–
• Series 2009		
Clean renewable energy bond, 1.81%, due 2024	**15,155**	–
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, 6.75% to 6.80%, due serially from 2010 through 2012	**29,177**	37,702
• Series 2003A Burke, Heard, Monroe and 2003B Burke		
Auction rate bonds, 0.35%, due 2024	**95,230**	95,230
• Series 2004 Burke and Monroe		
Auction rate bonds, 0.35%, due 2020	**11,525**	11,525
• Series 2005 Burke and Monroe		
Auction rate bonds, 0.29%, due 2040	**15,865**	15,865
• Series 2006B Monroe, 2006C-1 and C-2 Burke		
Term rate bonds, 4.63% through March 31, 2010, due 2036 through 2037	**133,550**	133,550
• Series 2007A Appling and Monroe, 2007B Appling and Burke, 2007C through F Burke		
Term rate bonds, 4.75% through March 31, 2011, due 2038 through 2040	**133,493**	135,223
• 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, 6.50% through March 31, 2011, due 2038 through 2039	**41,125**	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, 0.22%, due 2030 through 2038	**112,055**	–
CoBank, ACB notes payable:		
• Transmission mortgage note payable: fixed at 3.72% through March 9, 2010, due in bimonthly installments through November 1, 2018	**1,310**	1,388
• Transmission mortgage note payable: fixed at 3.72% through March 9, 2010, due in bimonthly installments through September 1, 2019	**5,258**	5,524
Total long-term debt	**4,267,706**	3,361,463
Obligations under capital leases	**239,461**	264,107
Obligation under Rocky Mountain transactions, long-term	**115,641**	108,219
Patronage capital and membership fees	**562,219**	535,829
Accumulated other comprehensive deficit	**(1,253)**	(1,348)
Subtotal	**5,183,774**	4,268,270
Less: long-term debt and capital leases due within one year	**(119,241)**	(110,647)
Total capitalization	**$ 5,064,533**	$ 4,157,623

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, 2009, 2008 and 2007

	(dollars in thousands)		
	2009	2008	2007
Cash flows from operating activities:			
Net margin	**$ 26,390**	$ 19,259	$ 19,061
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	**233,530**	213,804	222,334
Accretion cost	**18,261**	17,149	16,169
Amortization of deferred gains	**(5,660)**	(5,660)	(5,660)
Allowance for equity funds used during construction	**(2,394)**	(3,075)	(1,802)
Deferred outage costs	**(35,464)**	(30,926)	(36,550)
Loss (gain) on sale of investments	**6,938**	40,299	(8,610)
Regulatory deferral of costs associated with nuclear decommissioning	**(18,465)**	(48,488)	3,631
Other	**(5,021)**	(16)	(423)
Change in operating assets and liabilities:			
Receivables	**1,064**	(37,285)	28,946
Inventories	**(29,703)**	(25,479)	(13,875)
Prepayments and other current assets	**(3,480)**	(1,062)	(323)
Accounts payable	**(1,876)**	(1,582)	1,050
Accrued interest	**16,408**	14,386	(34,336)
Accrued and withheld taxes	**5,996**	11,705	(34,633)
Other current liabilities	**6,639**	(8,268)	8,051
Increase in Members' advances	**195,514**	5,000	–
Settlement of interest rate swaps	**–**	(33,771)	–
Total adjustments	**382,287**	106,731	143,969
Net cash provided by operating activities	**408,677**	125,990	163,030
Cash flows from investing activities:			
Property additions	**(627,148)**	(353,831)	(194,739)
Plant acquisitions	**(274,251)**	–	–
Activity in decommissioning fund – Purchases	**(635,081)**	(751,201)	(535,898)
– Proceeds	**630,055**	743,728	526,832
Activity in bond, reserve and construction funds – Purchases	**(474)**	(78)	(5,616)
– Proceeds	**1,052**	1,132	6,502
(Increase) decrease in restricted cash and cash equivalents	**(12,150)**	37,869	(29,812)
Increase in restricted short-term investments	**(80,590)**	–	–
(Increase) decrease in investment in associated organizations	**(9,033)**	4,788	(1,491)
Activity in other long-term investments – Purchases	**(1,963)**	(185,054)	(649,770)
– Proceeds	**2,600**	193,413	660,956
Other	**(4,522)**	(4,507)	(5,265)
Net cash used in investing activities	**(1,011,505)**	(313,741)	(228,301)
Cash flows from financing activities:			
Long-term debt proceeds	**992,246**	523,431	755,135
Long-term debt payments	**(110,905)**	(593,879)	(775,573)
Increase in notes payable	**143,634**	140,000	–
Debt related costs	**(21,812)**	(9,210)	(51,693)
Other	**11,075**	4,138	4,575
Net cash provided by (used in) financing activities	**1,014,238**	64,480	(67,556)
Net increase (decrease) in cash and temporary cash investments	**411,410**	(123,271)	(132,827)
Cash and temporary cash investments at beginning of period	**167,659**	290,930	423,757
Cash and temporary cash investments at end of period	**$ 579,069**	$ 167,659	$ 290,930
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	**$ 193,897**	$ 181,390	$ 235,130
Supplemental disclosure of non-cash investing and financing activities:			
Plant expenditures included in ending accounts payable	**$ (969)**	$ (10,529)	$ 10,099

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 DEFICIT
For the years ended December 31, 2009, 2008 and 2007

(dollars in thousands)

	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Deficit	Total
Balance at December 31, 2006	$ 497,509	$ (28,988)	$ 468,521
Components of comprehensive margin in 2007:			
Net margin	19,061	–	19,061
Unrealized loss on interest rate swap arrangements	–	(4,222)	(4,222)
Unrealized gain on available-for-sale securities	–	519	519
Total comprehensive margin			15,358
Balance at December 31, 2007	516,570	(32,691)	483,879
Components of comprehensive margin in 2008:			
Net margin	19,259	–	19,259
Realized deferred loss on interest rate swap arrangements	–	32,806	32,806
Unrealized loss on available-for-sale securities	–	(1,463)	(1,463)
Total comprehensive margin			50,602
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

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 5,594 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 39^{th} member. Flint did not have a percentage capacity responsibility from any of our generation resources in 2009; 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 as of, and for the period ended December 31, 2009 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. This means that our accounts are combined with the subsidiaries' accounts. We have eliminated any intercompany profits and transactions in consolidation.

We follow generally accepted accounting principles in the United States. We track 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.

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, 2009 and 2008 and the reported amounts of revenues and expenses for each of the three years ending December 31, 2009. 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 percentage capacity responsibility.

Any distributions of patronage capital are subject to the discretion of our board of directors, subject to mortgage indenture requirements. Under the 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 deficit

The table below provides detail regarding the beginning and ending balance for each classification of other comprehensive deficit along with the amount of any reclassification adjustments included in margin for each of the years presented in the Statement of Patronage Capital and Membership Fees and Accumulated Other Comprehensive Deficit (see Note 2).

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

Accumulated Other Comprehensive Deficit

	Interest Rate Swap Arrangements	Available-for-sale Securities	Total
	(dollars in thousands)		
Balance at December 31, 2006	$ (28,584)	$ (404)	$ (28,988)
Unrealized gain (loss)	(4,222)	519	(3,703)
Balance at December 31, 2007	(32,806)	115	(32,691)
Realized deferred loss	32,806	–	32,806
Unrealized loss	–	(1,463)	(1,463)
Balance at December 31, 2008	–	(1,348)	(1,348)
Unrealized gain	–	95	95
Balance at December 31, 2009	**$ –**	**$ (1,253)**	**$ (1,253)**

e. Margin policy

We are required under the indenture to produce a margins for interest ratio of at least 1.10. For the years 2009, 2008 and 2007, we achieved a margins for interest ratio of 1.12, 1.10 and 1.10 respectively.

f. Operating revenues

Operating revenues 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. Energy furnished 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 non-members consisted primarily from services provided to Flint prior to it becoming a member of ours in December 2009.

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2009, 2008 and 2007:

	2009	2008	2007
Cobb EMC	**15.0%**	12.8%	13.3%
Jackson EMC	**11.6%**	11.4%	12.3%
Sawnee EMC	**10.2%**	10.4%	10.0%

g. Receivables

Substantially all 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 are 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 2009, 2008 and 2007 amounted to $52,163,000, $48,987,000, and $50,138,000, 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 Company, 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 until 2015.

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, 2009. 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 and Conditional Asset Retirement Obligations. The liability recognized primarily relates to our nuclear facilities. We also recognized retirement obligations for ash ponds, landfill sites and asbestos removal.

Under the provisions of Accounting for the Effects of Certain Types of Regulation, we may 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 for both the cumulative effect of adoption and for future period timing differences. The Rural Utilities Service approved our adoption of Accounting for the Effects of Certain Types of Regulation. There was no cumulative effect to net margin resulting from adopting the accounting for Asset Retirement Obligations and Conditional Asset Retirement Obligations. We estimate an annual decrease of approximately $2,100,000 over the next several years to the regulatory asset.

Accounting for Asset Retirement Obligations does not permit non-regulated entities to continue accruing 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. These costs are reflected on the balance sheet as ''Accumulated retirement costs for other obligations'' under the caption ''Deferred credits and other liabilities.''

In December 2009, Georgia Power provided us with 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 guidance related to Accounting for 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 2009 and 2008.

(dollars in thousands)

	Balance at 12/31/08	Liabilities Incurred (Settled)	Accretion	Change in Cash Flow Estimate	**Balance at 12/31/09**
Nuclear decommissioning	$ 273,034	$ –	$ 17,704	$ (35,084)	**$ 255,654**
Other	8,424	–	557	–	**8,981**
Total	$ 281,458	$ 0	$ 18,261	$ (35,084)	**$ 264,635**

(dollars in thousands)

	Balance at 12/31/07	Liabilities Incurred (Settled)	Accretion	Change in Cash Flow Estimate	Balance at 12/31/08
Nuclear decommissioning	$ 256,408	$ –	$ 16,626	$ –	$ 273,034
Other	8,918	(60)	523	(957)	8,424
Total	$ 265,326	$ (60)	$ 17,149	$ (957)	$ 281,458

As previously discussed, we defer the timing differences between cost recognition under Accounting for Asset Retirement Obligations and cost recovery for ratemaking purposes. Increases and decreases to the regulatory asset are reflected on the accompanying balance sheets as ''Deferred asset retirement obligations costs, being amortized'' and increases or decreases to the regulatory liability are reflected as ''Deferred liability associated with retirement obligations, being amortized'' under the caption ''Deferred credits and other liabilities.''

Consistent with our ratemaking, unrealized gains and losses from the decommissioning trust fund are recorded as an increase or decrease to the regulatory asset or liability.

j. Nuclear decommissioning trust fund

The Nuclear Regulatory Commission 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 and invested in accordance with applicable requirements of our Board of Directors and the Nuclear Regulatory Commission. Funds are invested in a diversified mix of equity and fixed income securities. At December 31, 2009 and 2008, equity securities comprised 55% and 51% of the external funds and fixed income securities comprise 45% and 49%, respectively. The Nuclear Regulatory Commission's minimum external funding requirements are based on a generic estimate of the cost to decommission the radioactive portions of a nuclear unit based on the size and type of reactor. We have filed plans with the Nuclear Regulatory Commission to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the Nuclear Regulatory Commission. We also maintain internal reserves that can be transferred to the external trust fund as needed. All realized gains (losses) and earned income associated with the nuclear decommissioning fund are reflected within the ''Cash flows from operating activities'' and ''Cash flows from investing activities'' sections, respectively, of our cash flow statement. Purchases, including reinvestments of earned income, and sales are reflected in the ''Activity in decommissioning fund'' line of the ''Cash flows from investing activities'' section of the cash flow statement. For the periods ending December 31, 2009 and 2008, realized losses totaled ($663,000) and ($32,239,000), respectively.

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. The 2009 site study received from Georgia Power resulted in a decrease in the estimated cost of decommissioning Plants Hatch and Vogtle. 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 recorded any provision for decommissioning during the years 2009, 2008 and 2007 because the balance in the decommissioning trust fund at December 31, 2009 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 6.5% earnings rate for our decommissioning trust fund assets. Since inception (1990) to 2009, the nuclear decommissioning trust fund has produced a return in excess of 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. Annual depreciation rates, as approved by the Rural Utilities Service, in effect in 2009, 2008 and 2007 were as follows:

	Range of Useful Life in years*	**2009**	2008	2007
Steam production	49-65	**1.52%**	1.42%	1.47%
Nuclear production	37-60	**1.90%**	2.39%	2.42%
Hydro production	50	**2.00%**	2.00%	2.00%
Other production	27-33	**3.00%**	3.03%	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 2009.

Depreciation expense for the years 2009, 2008 and 2007 was $133,235,000, $119,067,000, and $130,962,000, respectively. In 2007, under the provisions of Accounting for the Effects of Certain Types of Regulation, we began deferring the difference between Plant Vogtle depreciation expenses based on the current 40-year operating license versus depreciation expenses based on the applied for 20-year license extension. For further discussion of the depreciation deferral, see Note 1(t). On June 3, 2009, the Nuclear Regulatory Commission granted 20 year license extensions for Plant Vogtle Units No. 1 and No. 2.

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. The cost of equity and debt funds is calculated at the embedded cost of all such funds. For the years ended 2009, 2008 and 2007, the allowance for funds used during construction rates used were 5.54%, 6.10% and 6.24%, 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. Bond, reserve and construction funds

Bond, reserve and construction funds for pollution control revenue bonds are maintained as required by our bond agreements. Bond funds serve as payment clearing accounts, reserve funds maintain amounts equal to the maximum annual debt service of each bond issue and construction funds hold bond proceeds for which construction expenditures have not yet been made. As of December 31, 2009 and 2008, all of the funds were invested in either U.S. Government securities or money market accounts.

n. 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.

o. Restricted cash

The restricted cash balance at December 31, 2009 consisted of $10,940,000 utilized in January 2010 for payment of principal on certain pollution control bonds and $11,465,000 of cash on deposit with CoBank for clean renewable energy projects. In 2008, $10,255,000 of restricted cash was utilized in January of 2009 for payment of principal on certain pollution control bonds.

p. Restricted short-term investments

At December 31, 2009, we had $80,590,000 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.

q. 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.

Inventories include principally spare parts and fossil fuel. 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, 2009 and 2008, fossil fuels inventories were $101,993,000 and $72,891,000, respectively. Inventories for spare parts at December 31, 2009 and 2008 were $107,844,000 and $102,459,000, respectively.

r. Deferred charges

We account for both coal-fire outage and nuclear refueling outage costs as deferred outage costs. Coal-fired plant outage costs, which are accounted for as regulatory assets, are deferred and subsequently amortized on a straight-line basis to expense over an 18 to 24-month period. Nuclear refueling outage costs, accounted for as regulatory assets, are deferred and subsequently amortized to expense over the 18-month and 24-month operating cycles of each unit.

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.

Premium and loss on reacquired debt represents premiums paid, together with any unamortized transaction costs, related to reacquired debt. This deferred charge is amortized in equal monthly amounts over the amortization period for the refunding debt.

As of December 31, 2009, the remaining amortization periods for debt issuance costs and premium and loss on reacquired debt range from approximately 1 to 33 years.

	(dollars in thousands)			
	Balance at 12/31/08	Additions	Amortization	**Balance at 12/31/09**
Outage costs	$ 27,137	$35,464	$ (31,282)	**$ 31,319**
Debt issuance costs	41,905	21,812	(6,455)	**57,262**
Premium (loss) on reacquired debt	130,013	5,413	(12,579)	**122,847**

s. Deferred credits and liabilities

As a result of the Rocky Mountain lease transactions, we recorded a net benefit of $95,560,000 which was deferred and is being amortized to income over the 30-year lease-back period. For further discussion on the Rocky Mountain lease transactions, see Note 2.

In conjunction with the Hawk Road Energy Facility 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 regarding the Hawk Road Energy Facility acquisition, see Note 13.

t. Regulatory assets and liabilities

We are subject to the provisions of Accounting for the Effects of Certain Types of Regulation. 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. Future revenues are expected to provide for recovery of previously incurred costs and are not calculated to provide for expected levels of similar future costs. 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.

In March 2008, we terminated both the AIG Financial Products Corp. and JPMorgan Chase Bank interest rate swap arrangements. We made a termination payment to AIG Financial Products of $36,611,000 and received a termination payment of $2,840,000 from JPMorgan Chase Bank. The amounts are recorded as a regulatory asset and liability, respectively, in accordance with Accounting for the Effects of Certain Types of Regulation, and are being amortized over the remaining life of the Series 1993A and Series 1994A pollution control bonds, or 2016 and 2019, respectively. The JPMorgan Chase Bank termination payment is reflected in the table below as ‘‘Other regulatory liabilities’’ and is included on the balance sheet under the caption ‘‘Deferred credits and other liabilities’’ in the line item ‘‘Other’’.

In December 2008, we recorded an other-than-temporary impairment on $7,300,000 of our auction rate securities issued by Anchorage Finance Sub-Trust, an investment vehicle of AMBAC Assurance Corp. that we had previously recorded as a temporary impairment, as a result of failed auctions, credit rating downgrades and the conversion of such securities to auction market preferred shares by AMBAC. The impairment is recorded as a regulatory asset under the provisions of Accounting for the Effects of Certain Types of Regulation and is reflected as ‘‘Deferred investment impairment losses’’ in the table below and is included on the balance sheet under the caption ‘‘Deferred charges’’ in the line item ‘‘Other.’’ This amount is being amortized as a charge to income over a period of seven years.

Effective July 1, 2007, we began deferring the difference between Plant Vogtle depreciation expenses based on the current 40-year operating license versus depreciation expenses based on the applied for 20-year license extension. The difference in the depreciation expenses are reflected in the ‘‘Deferred depreciation expense’’ line item in the table below. On June 3, 2009, the Nuclear Regulatory Commission granted 20-year license extensions for Plant Vogtle Units No. 1 and No. 2. Amortization of the deferred amount totaling $54,900,000 at May 31, 2009 to depreciation expense over the extended license period began in June 2009.

Other regulatory assets in the table below are included on the balance sheet under the caption ‘‘Deferred charges’’ in the line item ‘‘Other.’’

The following regulatory assets and (liabilities) are reflected on the accompanying balance sheets as of December 31, 2009 and 2008:

	(dollars in thousands)	
	2009	2008
Premium and loss on reacquired debt	**$ 122,847**	$ 130,013
Deferred amortization on capital leases	**77,755**	85,612
Deferred outage costs	**31,319**	27,137
Deferred interest rate swap termination fees	**29,296**	33,286
Asset retirement obligations	**31,412**	60,310
Deferred depreciation expense	**54,056**	42,955
Deferred investment impairment losses	**6,257**	7,300
Other regulatory assets	**4,984**	1,953
Accumulated retirement costs for other obligations	**(43,955)**	(49,675)
Net benefit of Rocky Mountain transactions	**(54,151)**	(57,336)
Other regulatory liabilities	**(10,358)**	(2,573)
Net assets (liabilities)	**$ 249,462**	$ 278,982

In the event that competitive or other factors result in cost recovery practices under which we can no longer apply the provisions of Accounting for the Effects of Certain Regulation, we would be required to eliminate all regulatory assets and liabilities that could not otherwise be recognized as assets and liabilities by businesses in general. In addition, we would be required to determine any impairment to other assets, including plant, and write-down those assets, if impaired, to their fair value.

All of the regulatory assets and liabilities included in the table above are being recovered or refunded to our members on a current, ongoing basis in our rates. The remaining recovery period for the regulatory assets ranges from approximately 1 to 38 years, except for the asset retirement obligations regulatory assets which have a recovery period of 9 to 38 years. The remaining refund period for the regulatory liabilities are approximately 17 years for the Rocky Mountain transactions and over the lives of the plants for accumulated retirement costs for other obligations.

u. Other income (expense)

The components of the other income (expense) line item within the Consolidated Statement of Revenues and Expenses were as follows:

		(dollars in thousands)	
	2009	2008	2007
Capital credits from associated companies (Note 2)	**$ 1,921**	$ 2,731	$ 1,875
Net revenue from Georgia Transmission and Georgia System Operations for shared Administrative and General costs	**1,375**	1,803	1,667
Miscellaneous other	**(447)**	(371)	693
Total	**$ 2,849**	$ 4,163	$ 4,235

v. Members' Advances

In December 2008, we instituted 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 funds. The advances are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited each and every month against the power bills and are recorded on our books as a reduction to member revenues. At December 31, 2009, member advances as reflected on the consolidated balance sheets, including unpaid discounts, were $200,514,000, of which, $182,514,000 is classified as current liabilities and $18,000,000 as deferred credits and other liabilities in the consolidated balance sheets. Subsequent to December 31, 2009, we received an additional $30,500,000 from members under this program. The advances are being applied against members' power bills through September 2013, with the majority scheduled to be applied in 2010.

w. Presentation

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

x. New accounting pronouncements

In September 2009, we adopted the FASB Codification and the Hierarchy of Generally Accepted Accounting Principles (Codification). The Codification creates a two-level GAAP hierarchy – authoritative and non-authoritative – and establishes the Codification as the sole source of authoritative GAAP for non-governmental entities, except for rules and interpretive releases by the SEC. The Codification had no impact on our results of operations, cash flows or financial condition.

Effective January 1, 2009, we adopted FASB authoritative guidance issued regarding Disclosures about Derivative Instruments and Hedging Activities. The standard is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures that reflect the effect of these activities on an entity's financial position, financial performance, and cash flows. For a discussion of the effect of derivative instruments and hedging activities on our results of operations, cash flows and financial condition, see Note 2.

In November 2007, the FASB issued a one-year deferral for the implementation of Fair Value Measurements for non-financial assets and non-financial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The deferral was applicable for asset retirement obligations measured at fair value upon initial recognition under Accounting for Asset Retirement Obligations, or upon a remeasurement event. We adopted Fair Value Measurements for non-financial assets and non-financial liabilities effective January 1, 2009 with no material effect on our results of operations, cash flows or financial condition.

Effective June 30, 2009, we adopted FASB standard Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly. The standard emphasizes that even if there has been a significant decrease in the volume and level of activity for the asset or liability and regardless of the valuation technique and inputs used, the objective for the fair value measurement is unchanged from what it would be if markets were operating at normal activity levels or transactions were orderly; that is, to determine the current exit price. The standard sets forth additional factors that should be considered to determine whether there has been a significant decrease in the volume and level of activity when compared with normal market activity. The reporting entity should evaluate the significance and relevance of the factors to determine whether, based on the weight of evidence, there has been a significant decrease in activity and volume. The standard indicates that if an entity determines that either the volume or level of activity for an asset or liability has significantly decreased (from normal conditions for that asset or liability) or price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The standard further notes that a fair value measurement should include a risk adjustment to reflect the amount market participants would demand because of the risk (uncertainty) in the cash flows.

This standard also requires a reporting entity to make additional disclosures in interim and annual periods. Revisions resulting from a change in valuation techniques or their application are accounted for as a change in accounting estimate. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective June 30, 2009, we adopted FASB authoritative guidance Interim Disclosures about Fair Value of Financial Instruments. The standard requires disclosures about the fair value of financial instruments in interim and annual financial statements. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective June 30, 2009, we adopted FASB standard Subsequent Events. The standard establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires management to evaluate events or transactions that may occur for potential recognition of disclosure in the financial statements, the circumstances under which events or transactions occurring after the balance sheet date should be recognized and events or transactions that should be disclosed that occur after the balance sheet date. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective January 1, 2010, we adopted FASB standard for Accounting for Transfers of Financial Assets – an amendment of Accounting for Transfers for

Servicing of Financial Assets and Extinguishments of Liabilities. The standard requires improved disclosures about transfers of financial assets and removes the exception from applying Consolidation of Variable Interest Entities to qualifying special purpose entities. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

Effective January 1, 2010, we adopted FASB standard Amendments to Consolidation of Variable Interest Entities. The standard provides new consolidation guidance for variable interest entities and requires a company to assess the determination of the primary beneficiary of a variable interest entity based on whether the company has the power to direct matters that most significantly impact the activities of the entity, and the obligation to absorb losses or the right to receive benefits of the entity. The standard also requires ongoing reassessments of whether a company is the primary beneficiary of a variable interest entity. The adoption of the standard did not have a material effect on our results of operations, cash flows or financial condition.

2. Fair value of 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 GAAP, 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

The table below details assets and liabilities measured at fair value on a recurring basis for the periods ending December 31, 2009 and 2008, respectively.

		Fair Value Measurements at Reporting Date Using			
	December 31, 2009	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	**$ 239,746**	$ 238,543	$ 1,463	$ (260)	(1) (3)
Bond, reserve and construction funds	**3,982**	3,982	–	–	(1)
Long-term investments	**87,129**	60,119	–	27,010	(1) (3)
Natural gas swaps	**(12,516)**	–	(12,516)	–	(1)
Deposit on Rocky Mountain transactions	**115,641**	–	–	115,641	(3)
Investments in associated companies	**53,199**	–	–	53,199	(3)

		Fair Value Measurements at Reporting Date Using			
	December 31, 2008	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	$ 201,094	$ 184,854	$ 10,155	$ 6,085	(1) (3)
Bond, reserve and construction funds	4,560	4,560	–	–	(1)
Long-term investments	81,550	51,907	–	29,643	(1) (3)
Natural gas swaps	(18,836)	–	(18,836)	–	(1)
Deposit on Rocky Mountain transactions	108,219	–	–	108,219	(3)
Investments in associated companies	43,441	–	–	43,441	(3)

The following tables present the changes in Level 3 assets and liabilities measured at fair value on a recurring basis during the twelve months ended December 31, 2009 and 2008, respectively.

	Twelve Months Ended December 31, 2009			
	Decommissioning funds	Long-term investments	Deposit on Rocky Mountain transactions	Investments in associated companies
	(dollars in thousands)			
Assets:				
Balance at December 31, 2008	$ 6,085	$ 29,643	$ 108,219	$ 43,441
Total gains or losses (realized/unrealized):				
Included in earnings	(225)	–	–	–
Included in regulatory asset	97	–	–	–
Impairment included in other comprehensive deficit	–	(33)	–	–
Purchases, issuances, liquidations	–	(2,600)	–	–
Transfers to Level 3	(6,217)	–	7,422	9,758
Balance at December 31, 2009	**$ (260)**	**$ 27,010**	**$ 115,641**	**$ 53,199**

	Twelve Months Ended December 31, 2008			
	Decommissioning funds	Long-term investments	Deposit on Rocky Mountain transactions	Investments in associated companies
	(dollars in thousands)			
Assets:				
Balance at January 1, 2008	$ 1,342	$ 7,300	$ 101,272	$ 46,449
Total gains or losses (realized/unrealized):				
Included in earnings	(92)	–	–	–
Included in regulatory asset	5	(7,300)	–	–
Impairment included in other comprehensive deficit	–	(1,657)	–	–
Purchases, issuances, liquidations	–	(15,000)	–	–
Transfers to Level 3	4,830	46,300	6,947	(3,008)
Balance at December 31, 2008	$ 6,085	$ 29,643	$ 108,219	$ 43,441
	Interest Rate Swaps			
Liabilities:				
Balance at January 1, 2008	$ 30,526			
Total gains or losses (realized/unrealized):				
Included in other comprehensive deficit	3,245			
Included in regulatory assets and liabilities	(33,771)			
Balance at December 31, 2008	$ –			

The assets included in the ''Long-term investments'' column in each of the 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, 2009, we held auction rate securities with maturity dates ranging from March 15, 2028 to December 1, 2045.

Based on the fair value of these auction rate securities as of December 31, 2009, an additional temporary impairment of approximately $33,000 was recorded as an incremental adjustment to the $1,657,000 that was previously recorded at December 31, 2008. The temporary impairment is reflected in ''Accumulated other comprehensive 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. If the market for our auction rate securities investments should deteriorate, we may need to increase the illiquidity premium used in preparing a discounted cash flow model for these securities. A 25 basis point increase in the illiquidity premium used to determine the fair value of these investments at December 31, 2009, would have resulted in a decrease in the fair value of our auction rate securities investments by approximately $1,503,000.

These investments were rated either A3 or Aaa by Moody's Investors Service and AAA by Standard and Poor's as of December 31, 2009. Therefore, it is expected that the investments will not be settled at a price less than par value. Because we have the ability and intent to hold these investments until a recovery of our original investment value, we considered the investments to be temporarily impaired at December 31, 2009.

In December 2008, we recorded an other-than-temporary impairment on $7,300,000 of our auction rate securities that had previously been recorded as a temporary impairment, as a result of failed auctions, credit rating downgrades and the conversion of such securities to auction market preferred shares by AMBAC. The impairment was recorded as a regulatory asset and are reflected on the balance sheet, under the caption ''Deferred charges'', in the line item ''Other.''

The estimated fair values of our long-term debt at December 31, 2009 and 2008 were as follows (in thousands):

	2009		2008	
	Cost	**Fair Value**	Cost	Fair Value
Long-term debt	**$ 4,178,981**	**$ 4,500,762**	$ 3,278,856	$ 3,730,183

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 the Rural Utilities Service 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 and Rural Utilities Service are based on U.S. Treasury rates as of December 31, 2009 (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 to an ''A'' rated borrower. 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.

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 committee provides general oversight over all risk management activities, including but not limited to, commodity trading and investment portfolio management. We use commodity trading derivatives, which are designated as hedging instruments under authoritative guidance for Accounting for Derivatives and Hedging Activities, 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 the natural gas swaps are reflected as an unbilled receivable. 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. 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.

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, 2009, the estimated fair value of our natural gas contracts was an unrealized loss of approximately $12,516,000.

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 could cause us to have credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of December 31, 2009, all of the counterparties with transaction amounts outstanding in our hedging portfolio are rated above investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated above investment grade.

We have entered into International Swaps and Derivatives Association Agreements with our natural gas hedge 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 counterparties' credit standing, including those experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies, or have changes in ownership. 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. We may only post credit support in the form of a letter of credit due to provisions within our Rural Utilities Service Loan Contract; however, we may receive collateral in the form of cash or credit support. As of December 31, 2009, neither we nor any counterparties were required to post credit support or collateral under any of these agreements. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009 due to our credit rating being downgraded below investment grade, we could have been required to post letters of credit totaling up to $12,516,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives and derivatives within our nuclear decommissioning trust fund as of December 31, 2009 that are expected to settle each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)	Derivative Instruments (in millions)
2010	5.57	7.60
2011	0.95	0.60
2014	0.00	1.92
2016	0.00	0.08
Total	**6.52**	**10.20**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets for the period ending December 31, 2009.

	Balance Sheet Location	Fair Value
		(dollars in thousands)
Designated as hedges under authoritative guidance related to derivatives and hedging activities:		
Assets		
Natural Gas Swaps	Receivables	**$ 12,520**
Natural Gas Swaps	Receivables	**(4)**
Total assets designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 12,516**
Liabilities		
Natural Gas Swaps	Other current liabilities	**$ 12,520**
Natural Gas Swaps	Other current liabilities	**(4)**
Total liabilities designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 12,516**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities:		
Assets		
Nuclear decommissioning trust	Decommissioning fund	**$ 8,380**
Nuclear decommissioning trust	Decommissioning fund	**(8,640)**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**8,479**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**(8,382)**
Total not designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ (163)**

The following table presents the gains and (losses) on derivative instruments recognized in income for the twelve months ending December 31, 2009.

Effect of Derivative Instruments on the Consolidated Statement of Revenues and Expenses

	Income Statement Location	Twelve months ended
		(dollars in thousands)
Designated as hedges under authoritative guidance related to derivatives and hedging activities		
Natural Gas Swaps	Purchase power	**$ 46**
Natural Gas Swaps	Purchase power	**(30,635)**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities		
Nuclear decommissioning trust	Investment income	**3,477**
Nuclear decommissioning trust	Investment income	**(3,702)**
Total losses on derivatives		**$ (30,814)**

In 1993, we entered into two interest rate swap arrangements with AIG Financial Products, for the purpose of securing a fixed rate lower than otherwise would have been available to us had we issued fixed rate bonds at that time. Under these swap arrangements, we made payments to the counterparty based on the notional principal at a contractual fixed rate and the counterparty made payments to us based on the notional principal at the existing variable rate of the refunding bonds (Series 1993A and Series 1994A). The differential to be paid or received was accrued as interest rates changed and was recognized as an adjustment to interest expense. The notional principal amount was used to measure the amount of the swap payments and did not represent additional principal due to the counterparty. A portion (16.86%) of the AIG Financial Products interest rate swap arrangements were assumed by Georgia Transmission in connection with a corporate restructuring. We classified our portion of the two interest rate swap arrangements as cash flow hedges. In March 2008, we terminated the AIG Financial Products swaps. The termination payment to AIG Financial Products of $36,611,000 was recorded as a regulatory asset to reflect future cost recovery and is being amortized to expense over the remaining life of the Series 1993A notes and Series 1994A notes, or 2016 and 2019, respectively.

We also entered into swap arrangements with JP Morgan Chase in 2006. These swaps used as notional principal, our 83.14% share of the Series 1993A and

Series 1994A bonds and were designed to convert the contractual variable rate of interest we received under the swaps with AIG Financial Products to a longer-term contractual variable rate of interest we received from JP Morgan Chase. In March 2008, we terminated the JP Morgan Chase swaps. The termination payment received from JP Morgan Chase of $2,840,000 was recorded as a regulatory liability to reflect future refunds and is being amortized to expense over the remaining life of the Series 1993A notes and Series 1994A notes, or 2016 and 2019, respectively.

Investments in debt and equity securities

Under Accounting for Certain Investments in Debt and Equity Securities, investment securities we hold are classified as either available-for-sale or held-to-maturity. 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. Unrealized gains and losses from investment securities held in the decommissioning fund, which are also classified as available-for-sale, are directly added to or deducted from deferred asset retirement obligations costs. Held-to-maturity securities are carried at cost. There were no held-to-maturity securities as of December 31, 2009 and 2008. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 78% of these gross unrealized losses were in effect for less than one year. These losses were primarily due to investments in fixed income securities held in the nuclear decommissioning trust fund. Consistent with our ratemaking, unrealized gains and losses from the decommissioning trust fund are recorded as an increase or decrease to the regulatory asset.

For those securities considered to be available-for-sale, the following table summarizes the activities for those securities as of December 31, 2009 and 2008:

(dollars in thousands)				
		Gross Unrealized		
2009	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 127,704**	**$ 35,003**	**$ (3,671)**	**$ 159,036**
Debt	**170,033**	**15,685**	**(13,089)**	**172,629**
Other	**(815)**	**7**	**–**	**(808)**
Total	**$ 296,922**	**$ 50,695**	**$ (16,760)**	**$ 330,857**
		Gross Unrealized		
2008	Cost	Gains	Losses	Fair Value
Equity	$ 127,691	$ 8,113	$ (18,473)	$ 117,331
Debt	147,178	1,389	(3,888)	144,679
Other	25,180	14	–	25,194
Total	$ 300,049	$ 9,516	$ (22,361)	$ 287,204

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, 2009 and 2008 are as follows:

(dollars in thousands)	**2009**		2008	
	Cost	**Fair Value**	Cost	Fair Value
Due within one year	**$ 38,270**	**$ 39,377**	$ 51,109	$ 49,568
Due after one year through five years	**39,171**	**50,625**	28,814	28,927
Due after five years through ten years	**20,668**	**21,086**	17,924	17,975
Due after ten years	**71,924**	**61,541**	49,331	48,209
Total	**$ 170,033**	**$ 172,629**	$ 147,178	$ 144,679

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2009, 2008 and 2007:

(dollars in thousands)	For the years ended December 31,		
	2009	2008	2007
Gross realized gains	**$ 17,537**	$ 9,430	$ 15,492
Gross realized losses	**(24,475)**	(49,729)	(6,882)
Proceeds from sales	**633,707**	978,573	533,334

Investment in associated companies, at cost

Investments in associated companies were as follows at December 31, 2009 and 2008:

	(dollars in thousands)	
	2009	2008
National Rural Utilities Cooperative Finance Corporation (CFC)	**$ 23,977**	$ 13,977
CoBank, ACB	**3,321**	3,203
CT Parts, LLC	**3,488**	3,162
Georgia Transmission Corporation	**15,977**	14,469
Georgia System Operations Corporation	**5,136**	7,396
Other	**1,300**	1,234
Total	**$ 53,199**	$ 43,441

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 2013.

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 fair value.

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 a guaranteed investment contract which will be held to maturity (the end of the 30-year lease-back period). At the end of the base lease term, we intend, through RMLC, to repurchase tax ownership and to retain all other rights of ownership with respect to the facility if it is advantageous to do so. If we elect to repurchase the facility, the funds in the guaranteed investment contract will be used to pay a portion ($371,850,000) of the fixed purchase price.

In addition to the funding of the guaranteed investment contract, 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 AAA 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 repurchase 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 2009, RMLC would have been required to make basic rent payments totaling $56,954,000 to the owner trusts if the Payment Undertaker had failed to make such payment. 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 Aa2 from Moody's or AA from S&P, 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 Aa1 by Moody's and AA+ by S&P. 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 of 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.

There is a current tax benefit of $104,000 for refundable alternative minimum tax for the year ended December 31, 2009.

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

	2009	2008	2007
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Patronage exclusion	**(31.4%)**	(30.1%)	(32.3%)
Tax credits	**(0.1%)**	(0.1%)	0.0%
Other	**(3.6%)**	(4.9%)	(2.7%)
Effective income tax rate	**(0.1%)**	(0.1%)	0.0%

The components of the net deferred tax assets as of December 31, 2009 and 2008 were as follows:

	(dollars in thousands) **2009**	2008
Deferred tax assets		
Net operating losses	**$ 60,054**	$ 97,552
Tax credits (alternative minimum tax and other)	**1,633**	1,737
	61,687	99,289
Less: Valuation allowance	**(37,687)**	(51,289)
Net deferred tax assets	**$ 24,000**	$ 48,000
Deferred tax liabilities		
Depreciation	**$ –**	$ –
	–	–
Net deferred tax liabilities	**$ –**	$ –

As of December 31, 2009, 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
2010	–	–	77,970
2018	–	–	61,533
2019	–	–	10,516
2020	–	–	4,362
None	1,633	–	–
	$ 1,633	$ –	$ 154,381

The net operating loss expiration dates start in the year 2010 and end in the year 2021. 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 2008 to 2009 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.

In July 2006, the FASB issued authoritative guidance for Accounting for Uncertainty in Income Taxes – an Interpretation of Accounting for Income Taxes. The authoritative guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under Accounting for Uncertainty in Income Taxes, 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. Accounting for Uncertainty in Income Taxes also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We file a U.S. federal consolidated income tax return. The U.S. federal statute of limitations remains open for the year 2006 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 2006 forward.

As a result of the adoption of the authoritative guidance, 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 2008 and 2009, one of the three open years expired. Accordingly, this liability and related deferred tax asset was reduced by $24,000,000 during each third quarter. We are carrying forward significant regular tax and alternative minimum tax credits net operating losses. Therefore, any regular tax liability in the open year related to the uncertain tax position would be offset by regular net operating losses. However, we would be liable for the portion of alternative minimum tax for this period that is not allowed to be offset by the alternative minimum tax net operating losses. In the current open year, our exposure is not material to its consolidated results of operations, cash flows or financial position.

We recognize accrued interest with uncertain tax positions in interest expense in the consolidated statements of revenues and expenses. As of December 31, 2009, we have recorded approximately $220,000 for interest in the accompanying balance sheet. It is expected that the amount of unrecognized tax benefits will change in the next twelve months; however, we do not expect the change to have a significant impact on our results of operations, financial position or effective tax rate.

The unrecognized tax benefit reconciliation from beginning balance to ending balance is as follows for the years 2009, 2008, and 2007:

	(dollars in thousands)
Unrecognized tax benefit at beginning of year (January 1, 2007)	$ 96,000
Reduction of tax positions as a result of statue of limitation expiration	(24,000)
Unrecognized tax benefits at year end (December 31, 2007)	$ 72,000
Reduction of tax positions as a result of statue of limitation expiration	(24,000)
Unrecognized tax benefits at year end (December 31, 2008)	$ 48,000
Reduction of tax positions as a result of statue of limitation expiration	(24,000)
Unrecognized tax benefits at year end (December 31, 2009)	**$ 24,000**

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 the 36-year term of the leases.

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, 2009 are as follows:

Year Ending December 31,	(dollars in thousands)		
	Scherer Unit No. 2	Doyle	Total
2010	$ 31,860	$ 12,447	$ 44,307
2011	31,859	12,447	44,306
2012	31,772	12,447	44,219
2013	24,093	12,447	36,540
2014	16,326	12,447	28,773
2015-2021	114,283	18,298	132,581
Total minimum lease payments	250,193	80,533	330,726
Less: Amount representing interest	(77,524)	(13,741)	(91,265)
Present value of net minimum lease payments	172,669	66,792	239,461
Less: Current portion	(21,841)	(8,675)	(30,516)
Long-term balance	$ 150,828	$ 58,117	$ 208,945

The interest rate on the Scherer No. 2 lease obligation is 6.97%. For Doyle, the lease payments vary to the extent the interest rate on the lessor's debt varies from 6.00%. At December 31, 2009, the weighted average interest rate on the Doyle lease obligation was 6.02% as compared to 5.98% at December 31, 2008.

The Scherer No. 2 lease and the Doyle Agreement meet the definitional criteria to be 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 pursuant to Accounting for Effects of Certain Types of Regulation.

5. Long-term debt:

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

In February 2009, we issued $350,000,000 of Series 2009 A taxable fixed rate first mortgage bonds for the purposes of financing a portion of construction costs associated with new generation facilities, to enhance existing generation facilities and to provide liquidity for general corporate purposes. The first mortgage bonds are secured under the indenture.

In November 2009, we issued $400,000,000 of first mortgage bonds, Series 2009 B for the purpose of financing a portion of constructing Plant Vogtle Units No. 3 and No. 4 (including redeeming commercial paper issued in connection with the construction of these new nuclear units) and to provide liquidity for general corporate purposes. The first mortgage bonds are secured under the indenture.

In October, 2009, in conjunction with our acquisition of the Hartwell Energy Limited Partnership we assumed $61,500,000 of project level debt which we paid off immediately upon closing. In conjunction with the payoff of the debt, which included a make-whole prepayment provision, we also incurred a loss on reacquired debt of $5,413,000, which is being amortized over the life of the assets we acquired. We financed the total debt payoff price of $66,913,000 through the issuance of commercial paper.

In December 2009, we issued $112,055,000 of variable rate tax-exempt pollution control revenue bonds, including (i) $11,000,000 to refinance principal maturing on January 1, 2010 under existing pollution control revenue bonds, and (ii) $101,055,000 of new money tax-exempt pollution control revenue bonds related to the installation of scrubbers at Plant Wansley and a mercury control project at Plant Scherer. These tax-exempt bonds are secured under the indenture.

In December 2009, we issued $16,165,000 of clean renewable energy bonds at a 1.81% fixed rate of interest, to finance a portion of the cost of an overhaul and upgrade project underway at our Rocky Mountain facility. The clean renewable energy bonds are secured under the indenture.

The annual interest requirement on our long-term debt for 2010 is estimated to be $257,770,000.

Maturities for long-term debt and amortization of the capital lease obligations through 2014 are as follows:

	(dollars in thousands)				
	2010	2011	2012	2013	2014
FFB	$ 77,567	$ 81,244	$ 85,047	$ 88,157	$ 92,022
RUS	666	700	736	773	813
CoBank	387	435	490	551	621
PCBs[1]	9,095	9,710	10,371	–	–
CREBs	1,010	1,010	1,010	1,010	1,010
	88,725	93,099	97,654	90,491	94,466
Capital Leases[2]	30,516	29,657	32,508	25,726	18,705
Total	$ 119,241	$ 122,756	$ 130,162	$ 116,217	$ 113,171

(1) Amounts reflect only our 83.14% share of the pollution control bond maturities and do not include Georgia Tranmission assumed share. The 2010 maturity was refinanced in a December 2009 transaction, and a plan is in place to refinance the remaining $20 million of pollution control bond principal set to mature in January of each year through 2012.

(2) Amounts reflect the debt portion of annual amortization of capitalized lease obligations as reflected on the balance sheet.

The weighted average interest rate for long-term debt and capital leases was 5.41% at December 31, 2009 as compared to 5.58% at December 31, 2008.

We have $1,125,000,000 of committed credit arrangements comprised of six separate facilities with maturity dates that range from December 2010 to December 2013. These short-term credit facilities are for general working capital purposes and to provide temporary funding for future construction projects. Along with the lines of credit from CoBank, CFC and JPMorgan Chase, funds may also be advanced under the backup line of credit supporting commercial paper for general working capital purposes. Under certain of our committed lines of credit we have the ability to issue letters of credit totaling $450,000,000 in the aggregate. At December 31, 2009, we had $114,000,000 under one of these lines of credit in the form of a letter of credit supporting variable rate pollution control revenue bonds.

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, 2009 is as follows:

	(dollars in thousands)	
Plant	Investment	Accumulated Depreciation
In-service		
Owned property		
Vogtle Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	$ 2,718,958	$ (1,472,122)
Hatch Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	578,257	(345,156)
Wansley Units No. 1 & No. 2 *(Fossil – 30% ownership)*	389,165	(116,090)
Scherer Unit No. 1 *(Fossil – 60% ownership)*	503,763	(259,057)
Rocky Mountain Units No. 1, No. 2 & No. 3 *(Hydro – 75% ownership)*	566,609	(158,826)
Hartwell (Combustion Turbine – *100% ownership)*	232,629	(79,600)
Hawk Road (Combustion Turbine – *100% ownership)*	238,652	(40,694)
Talbot (Combustion Turbine – *100% ownership)*	279,790	(60,889)
Chattahoochee (Combined cycle – *100% ownership)*	299,117	(61,342)
Wansley (Combustion Turbine – *30% ownership)*	3,627	(2,813)
Transmission plant	71,515	(38,312)
Other	99,329	(58,743)
Property under capital lease:		
Plant Doyle (Combustion Turbine – *100% leasehold)*	126,990	(72,796)
Scherer Unit No. 2 (Fossil – 60% *leasehold)*	442,537	(226,775)
Total in-service	$ 6,550,938	$ (2,993,215)
Construction work in progress		
Generation improvements	$ 614,115	
Other	12,709	
Total construction work in progress	$ 626,824	

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 statement of revenues and expenses.

b. Construction

On August 26, 2009, the Nuclear Regulatory Commission issued an Early Site Permit and Limited Work Authorization to Southern Nuclear, on behalf of Georgia Power, Oglethorpe, the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (collectively, Owners), related to two additional nuclear units on the site of Plant Vogtle (Plant Vogtle Units No. 3 and No. 4). In March 2008, Southern Nuclear filed an application with the Nuclear Regulatory Commission for combined construction permits and operating licenses for the new units. If licensed by the Nuclear Regulatory Commission, Plant Vogtle Units No. 3 and No. 4 are scheduled to be placed in service in 2016 and 2017, respectively.

In April 2008, Georgia Power, acting for itself and as agent for the 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 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 No. 3 and No. 4 Agreement).

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, 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.

Payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle No. 3 and No. 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Owners may terminate the Vogtle No. 3 and No. 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain states of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle No. 3 and No. 4 Agreement under certain circumstances, including delays in receipt of the construction and operating license or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle No. 3 and No. 4 Agreement by the Owners, Owner insolvency, and certain other events.

On August 27, 2009, the Nuclear Regulatory Commission issued letters to Westinghouse revising the review schedules needed to certify the AP1000 standard design for new reactors and expressing concerns related to the availability of adequate information and the shield building design. The shield building protects the containment and provides structural support to the containment cooling water supply. Georgia Power is continuing to work with Westinghouse and the Nuclear Regulatory Commission to resolve these concerns. Any possible delays in the AP1000 design certification schedule, including those addressed by the Nuclear Regulatory Commission in their letters, are not currently expected to affect the projected commercial operation dates for Plant Vogtle Units No. 3 and No. 4.

There are pending technical and procedural challenges to the construction and licensing of Plant Vogtle Units No. 3 and No. 4. 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.

As of December 31, 2009, our total capitalized costs to date relating to Plant Vogtle Units No. 3 and No. 4 were approximately $353,072,000.

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 their 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 $759,000 in 2009, $677,000 in 2008 and $644,000 in 2007. Effective 2007, our contribution was 8% to the employer retirement contribution feature. Our contributions to the employer retirement contribution feature of the 401(k) plan were approximately $1,460,000 in 2009, $1,305,000 in 2008 and $775,000 in 2007.

8. Nuclear insurance:

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' nuclear generating facilities. In the event that losses exceed accumulated reserve funds, the members are subject to retroactive assessments (in proportion to their premiums). 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 $8,598,000 for each nuclear incident.

Georgia Power, on behalf of all the co-owners of Plants Hatch and Vogtle, has coverage under NEIL II, which provides insurance to cover decontamination, debris removal and premature decommissioning as well as 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. In the event of a loss, the amount of insurance available may not be adequate to cover property damage and other incurred expenses. Under the NEIL II policies, members are also subject to retroactive assessments in proportion to their premiums if losses exceed the accumulated funds available to the insurer under the policy. The portion of the NEIL II current maximum annual assessment for Georgia Power that would be payable by us, based on ownership share, is limited to approximately $10,172,000.

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.

The Price-Anderson Act limits public liability claims that could arise from a single nuclear incident to $12,600,000,000, which amount is to be 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 its 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 excludes any applicable state premium taxes. The next scheduled adjustment is due no later than October 29, 2013.

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

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.

9. Commitments:

a. Operating leases

As of December 31, 2009, our estimated minimum rental commitments for our operating leases over the next five years and thereafter are as follows:

Year Ending December 31,	(dollars in thousands)
2010	$ 5,235
2011	5,560
2012	5,777
2013	5,777
2014	5,777
Thereafter	20,393

Rental expenses totaled $5,230,000 in 2009, $5,157,000 in 2008 and $5,299,000 in 2007. The rental expenses for the leases are added to the cost of the fossil inventories.

10. Guarantees:

As of December 31, 2009 and 2008, our guarantees included those disclosed in Note 5 for pollution control bonds assumed by Georgia Transmission in connection with a corporate restructuring and in Note 2 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.

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:

Set forth below are environmental matters that could have an effect on our financial condition or results of operations. At this time, the resolution of these matters is uncertain, and we have made no accruals for such contingencies and cannot reasonably estimate the possible loss or range of loss with respect to these 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 and nitrogen oxides into the air and discharges of other pollutants, including heat, into 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. New requirements may substantially increase the cost of electric service by requiring changes in the design or operation of existing 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 and regulations. Should we fail to be in compliance with these requirements, it would constitute a default under such debt instruments. We cannot provide assurance that we will always be in compliance with current and future regulations.

12. Ad valorem tax matters:

Monroe County Appeal

We had appealed Monroe County's assessment for years 2003 through 2007 and accrued the disputed additional taxes in the amount of $22.7 million, which we had not paid to the County. Pursuant to a Consent Agreement and Release, Monroe County agreed not to seek the payment of any additional taxes for 2003 through 2007, and we withdrew our appeals for those years. Accordingly, the accrual of $22.7 million for the disputed taxes was reversed in 2007.

13. Plant acquisitions:

a. Hawk Road Energy Facility

On May 1, 2009, we acquired 100% of Heard County Power L.L.C. (Heard LLC) pursuant to a purchase and sale agreement dated February 25, 2009. Heard LLC owns 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. The acquisition related costs of $900,000 were expensed in the second quarter of 2009.

The following amounts represent the preliminary estimates of 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 have 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. 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.

b. Hartwell Energy Facility

On October 13, 2009, we acquired 100% of the Hartwell Energy Limited Partnership (HELP) pursuant to a purchase and sale agreement dated April 2, 2009. HELP owns 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.

The following amounts represent the preliminary estimates of 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 HELP acquisition for the period October 13, 2009 through December 31, 2009 was immaterial.

14. Subsequent Events

In accordance with the Codification, we have evaluated subsequent events up until the time that our financial statements were issued.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the accompanying consolidated balance sheets, consolidated statements of capitalization and the related 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 financial position of Oglethorpe Power Corporation and its subsidiaries (an Electric Membership Cooperative) at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our audits (which was an integrated audit in 2009). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
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, 2009 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, 2009 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.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited the effectiveness of our internal control over financial reporting as of December 31, 2009, as stated in their report, which is contained in Item 8 ''Financial Statements and Supplementary Data'' of this annual report on Form 10-K.

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, 2009, 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.'' 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. 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 candidate. 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	55	President and Chief Executive Officer
Michael W. Price	49	Executive Vice President, Chief Operating Officer
Elizabeth B. Higgins	41	Executive Vice President, Chief Financial Officer
William F. Ussery	45	Executive Vice President, Member and External Relations
W. Clayton Robbins	63	Senior Vice President, Governmental Affairs
Charles W. Whitney	63	Senior Vice President, General Counsel
Jami G. Reusch	47	Vice President, Human Resources
Directors:(1)		
Benny W. Denham	79	Chairman and At-Large Director
Marshall S. Millwood	60	At-Large Director
Bobby C. Smith, Jr.	56	At-Large Director
Larry N. Chadwick	69	Member Group Director (Group 1)
H.B. Wiley, Jr.	65	Member Group Director (Group 2)
Rick L. Gaston	62	Member Group Director (Group 2)
M. Anthony Ham	58	Member Group Director (Group 3)
C. Hill Bentley	62	Member Group Director (Group 3)
J. Sam L. Rabun	78	Vice-Chairman and Member Group Director (Group 4)
Jeffrey W. Murphy	46	Member Group Director (Group 4)
G. Randall Pugh	66	Member Group Director (Group 5)
Wm. Ronald Duffey	68	Outside Director

(1) Currently, our board of directors has two vacancies. We anticipate that the second member director for Group 1 will be elected at our annual meeting to be held on March 29, 2010. 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 Senior Vice President and Chief Financial Officer of Oglethorpe 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, where he managed the bank's eastern division, rural utilities. Mr. Smith is a Certified Public Accountant, 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 and is that entity's Treasurer and Chairman of their Risk Oversight and Audit Committee. Mr. Smith is also a director of the

Electric Power Research Institute (EPRI) and the Georgia Chamber of Commerce. In 2009, Mr. Smith was selected to serve on the Georgia Tech Advisory Board. Mr. Smith previously served as a director of En-Touch Systems, Inc. from 2001 to 2006 and as a member of the North American Electric Reliability Corporation Stakeholders Committee from 2005 to 2006. In 2009, 2008 and 2007, 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 member of the Research Advisory Committee and Renewables Executive Advisory Committee of the Electric Power Research Institute and serves on the Advisory Board of Garrard Construction.

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. In these positions, Ms. Higgins was responsible for competitive bidding analyses, rate designs, integrated resource planning studies, operational/dispatch studies, bulk power market analysis, merger analyses and litigation support. Ms. Higgins has a Bachelor of Industrial Engineering degree from the Georgia Institute of Technology 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's degree in Electrical Engineering from Auburn University and an associate degree in Science from Middle Georgia College.

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's areas of focus are energy, particularly nuclear energy, regulatory, construction and labor law. He 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. 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 2010. 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 2011. 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 Screven County Zoning and of the Sylvania Lions Club. Mr. Smith serves on the advisory council of the Southern States Cooperative's Statesboro Complex.

Larry N. Chadwick is a member group director (group 1). He has served on our board of directors since July 1989. His present term will expire in March 2011. He is also a member of the compensation committee. Mr. Chadwick is an engineer, with experience in the design of hydrogen gas plants. He is Chairman of the board of Cobb 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. He has been a director of Walton Electric Membership Corporation since June 1993, and served as its Chairman of the Board from June 2000 to June 2003. Mr. Wiley has a Bachelor of Science degree from the University of Georgia. Mr. Wiley served in the U.S. Army Engineers from 1968 to 1971 and is a Vietnam veteran.

Rick L. Gaston is a member group director (group 2). He has served on our board of directors since May 2008. His present term will expire in March 2011. He is also a member of the construction project committee. Mr. Gaston is the General Manager of Colquitt Electric Membership Corporation. Mr. Gaston has also served on the board of directors of Georgia Transmission.

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 2011. 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 2010. He is also a member of the audit committee. He is the Chief Executive Officer of Tri-County Electric Membership Corporation. He is President of 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 Bibb County Chamber of Commerce and the Georgia Chamber of Commerce, and is past President of the Jones County Chamber of Commerce. Mr. Bentley is a member, and a past President, of the Georgia Rural Electric Managers Association and a member of the Rural Electric Managers Development Council and Georgia Economic Developers Association. He is also 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 2010. 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 2011. 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. He is Chairman of the Board of First Georgia Banking Company (Jackson and Banks County) and Chairman of the Georgia System Operations Audit Committee. He also serves on the Board of Directors of First Georgia Bankshares Holding Company, Green Power Electric Membership Corporation and Georgia System Operations. He is a past director and Chairman of the Board of Directors of Regions Bank (Jackson County). 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., and now serves as Chair of the Advisory Board of the Bank of North Georgia – Fayette. 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 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-Fayette Hospital, Piedmont-Newnan Hospital and The Georgia Economic Development Corp. 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 financial 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. The members of the compensation committee are J. Sam L. Rabun, M. Anthony Ham and Larry N. Chadwick.

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, Rick L. Gaston, Marshall S. Millwood 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 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 and the value of financial assets. Furthermore, the board of directors receives regular 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, and changes to derivative hedge positions and overall corporate risk exposure. The risk management 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 activities, including commodity trading, fuels management, insurance procurement, debt management, and investment portfolio management. 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 DISCLOSURE ABOUT MARKET RISK."

Code of Ethics

We have adopted a Code of Ethics that applies to our executive officers and the controller. Our Code of Ethics is attached as an exhibit to this annual report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

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, 2009.

Name	Total Fees Earned or Paid in Cash
Member Directors	
Benny W. Denham, Chairman	$ 14,540
J. Sam L. Rabun, Vice-Chairman	$ 17,200
Marshall S. Millwood	$ 15,200
Larry N. Chadwick	$ 13,200
M. Anthony Ham	$ 13,200
H.B. Wiley, Jr.	$ 12,900
Gary A. Miller	$ 900(1)
Jeffrey W. Murphy	$ 10,400
C. Hill Bentley	$ 11,600
Gary W. Wyatt	$ 11,400(2)
R.L. Gaston	$ 13,100
Bobby C. Smith, Jr.	$ 12,600
G. Randall Pugh	$ 12,800(3)
Outside Directors	
Wm. Ronald Duffey	$ 31,500

(1) Mr. Miller's term as a member of our board of directors expired March 2009.

(2) Mr. Wyatt's term as a member of our board of directors expired January 2010.

(3) Mr. Pugh's compensation is paid directly to Jackson Electric Membership Corporation, where he serves as President and Chief Executive Officer.

During 2009, we paid our outside directors 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. Outside directors were also paid $1,000 per day for attending committee meetings, annual meetings of the members or other official business of ours. Member directors were paid a fee of $1,200 per board meeting and $800 per day for attending committee meetings, other meetings except annual meetings of the members, or other official business of ours 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. 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 chairman of the audit committee is paid an additional $400 per audit committee meeting for the time involved in fulfilling that role. Neither our outside directors nor member directors receive any perquisites or other personal benefits from us.

Compensation Discussion and Analysis

Overview of the Compensation Program

The compensation committee of the board of directors has responsibility for establishing, implementing and monitoring adherence with our compensation programs.

Compensation Philosophy and Objectives

Our compensation and benefits program is designed to establish and maintain competitive total compensation programs that will attract, motivate and retain the qualified and skilled work force necessary for our continued success. To help align compensation paid to executive officers with the achievement of corporate goals, 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, each component of total compensation is validated relative to market values on an annual basis through the assessment of market data and benchmarking of compensation.

Components of Total Compensation. The compensation committee determined that compensation packages for the fiscal year ended December 31, 2009 for our executive officers should be comprised of the following three primary components:

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

Base Salary. Base salary is designed to attract and retain executives who can assist us in meeting our corporate goals. We believe that executive officer base salaries should be compared to the median of the range of salaries for executives in similar positions and with similar responsibilities at comparable companies. Base salary is established, in part, by surveying the external market. The compensation committee and our president and chief executive officer also factor in corporate performance and changes in individuals' roles and responsibilities when making decisions regarding executive officers' base salaries.

Each of our executive officers has an employment agreement that provides for a minimum annual base salary and performance pay. See the narrative disclosure following the ''Summary Compensation Table'' below for additional information on the terms of the employment agreements.

Performance Pay. Performance pay is designed to reward executive officers based on our success in achieving the corporate goals discussed below. Each executive officer has the potential to earn 20% of their base pay in performance pay. Each executive officer's performance pay award for 2009 was based 100% on the achievement of corporate goals, as determined by the board of directors upon the compensation committee's recommendation.

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.

Establishing Compensation Levels

Role of the Compensation Committee. The compensation committee reviews changes to our compensation program for our officers, directors and employees and recommends such changes to the board of directors for approval. Specifically, the compensation committee approves our performance pay program, including the corporate goals related to such program. The compensation committee receives a comprehensive report on an annual basis regarding all facets of our compensation program.

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. The key member of management involved in the compensation process is our president and chief executive officer. Our president and chief executive officer, together with the other executive officers, identifies corporate performance objectives that are used to determine performance pay amounts. Our president and chief executive officer 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 review and approval. Our president and chief executive officer approves the compensation of our executive officers, other than the president and chief executive officer, and in certain circumstances provides an upward adjustment to the executive officers' base salary. The president and chief executive officer reports the executive officers' salaries to the compensation committee annually. Our president and chief executive officer's compensation is approved by the board of directors upon recommendation of the compensation committee.

Role of the Compensation Consultant. We engage a compensation consultant to assist us in reviewing our compensation program on a periodic basis. During 2009, we engaged Hewitt Associates, an outside global human resources consulting firm, to conduct a review of our overall compensation program. Hewitt Associates provided us with relevant market data that was used to analyze our compensation program in light of the compensation programs of our peers and also to ensure that our compensation program aligned with our stated compensation philosophy and objectives.

Assessment of Market Data and Benchmarking of Compensation

To remain competitive, we annually validate each component of total compensation paid to the executive officers relative to market values for compensation paid to similarly situated executives at companies we consider to be our peers. We refer to this practice as benchmarking and do not consider it the determinative factor in setting executive officers' compensation. Rather, we intend for benchmarking to supplement our other internal analyses regarding individual's performance in prior years and achievement of corporate goals that we consider when determining the performance pay component of executive officers' compensation.

Our management establishes its peer group of companies by reviewing surveys of market data that focus on the utility industry. Management annually reviews the peer group's composition to ensure the companies included are relevant for comparative purposes.

For 2009, our peer group was composed of the companies included in the utilities industry sector reported in the U.S. Mercer Benchmark Survey, the 2009 Towers Perrin Executive Energy Survey, the companies included in the Utilities & Energy industry sector of the Watson Wyatt Top Management Report and the 2008 National Rural Electric Cooperative Association Generation and Transmission Compensation Survey. Although there is a large variance in the size of the companies included in these surveys, we believe they serve as appropriate comparisons to us because they are in the utility industry. Therefore, these companies likely have operations similar to ours and executives who have responsibilities and perform roles similar to our executives. In addition, these are the companies with whom we primarily compete for executive talent.

The Mercer Benchmark Executive Survey includes 2,201 participants from a broad range of industry sectors with annual revenues ranging $299 million to $24 billion annually. We focus our comparison on utilities sector participants with annual revenues ranging from $1 billion to $3 billion annually. We focused our comparison on these companies because they are most similar to us in terms of industry sector and revenues.

The Towers Perrin Executive Energy Survey includes 98 participant companies with revenues ranging from less than $1 billion to greater than $6 billion annually. We typically focus on the participant companies that have revenues ranging from $1 billion to $3 billion when reviewing executive level compensation. We choose to focus on these companies because their revenues are most similar to ours.

The Watson Wyatt Top Management Report includes 1,531 participants from a variety of industries. We focus on the participant companies from the utilities and energy sectors.

The 2009 National Rural Electric Cooperative Association Generation and Transmission Compensation Survey includes 54 companies, including us, all of whom are its members. Although we believe compensation paid to executives at other electric cooperatives is a relevant comparison tool, we do not focus exclusively on these companies when benchmarking compensation because we are larger than most of the other companies included in this survey.

Assessment of Severance Arrangements

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. We negotiated each employment agreement with the executive officers 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 ours and that each performs his or her respective role while acting solely in our best interests. See "– Severance Arrangements" below for a discussion of the terms of each of the president and chief executive officer's and other executive officers' agreements.

The compensation committee last reviewed the president and chief executive officer's employment agreement in November 2009. 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 reviewed the terms of each of the other executive officers' agreements. In its review, the compensation committee considered the total amount of compensation each executive officer 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.

The compensation committee will continue to review these agreements annually.

Assessment of Corporate and Executive Officer Performance

Each year we draft a comprehensive set of corporate goals which are approved by our board of directors. For 2009, our corporate goals primarily involved the following components: (i) the operation of our plants by facility type, (ii) our financial performance for the year, including cost savings and risk reduction programs, (iii) quality of performance, (iv) environmental compliance, (v) safety, (vi) corporate compliance and (vii) future generation projects.

We chose to tie performance compensation to these corporate goals because they most appropriately measure what we aim to accomplish. For us to be successful we must perform sound asset management by acquiring and managing the power supply resources necessary to serve our customers effectively. To do this, we must operate efficiently, safely, and in a financially sound manner that meets the expectations of our members, as represented by our board of directors. We review these corporate goals annually and make adjustments as needed to ensure that we are consistently stretching our goal expectations.

Performance pay paid to our executive officers is determined based on our success in achieving each of the goals identified above. Our board of directors annually approves a weighted system for determining performance pay whereby we assign a percentage to each of the goals identified above. At the end of each fiscal year, we determine goal achievement for each of the seven categories. Based on the achievement for each category, we assign a percentage, up to the maximum percentage allowed for each category, to determine the amount of performance pay available to our executive officers. For each executive officer, we then multiply 20% of his or her base salary by the goal achievement percentage amount. For example, if we had a 90% corporate goal achievement rate in a given year, each executive officer's performance pay would equal (base salary × 20%) × (90%). Set forth below is a chart summarizing our corporate goal weighting system for 2009 as approved by our board of directors in January 2009:

Goal	Weighted Percentage
Operations	28%
Financial	23%
Quality	13%
Environmental Compliance	10%
Safety	5%
Corporate Compliance	1%
Future Generation	20%

We measure goal achievement in each of the above categories as follows: We base our operations achievements on how well each of our operating plants respond to system requirements. In reviewing our success in meeting our financial goals, we consider what cost savings and cost reduction programs are implemented in a given year that will result in cost savings either in the current year or on a long-term basis. We also consider whether any programs were implemented that may not have resulted in cost savings in the current year, but nonetheless increased the value of our assets or reduced potential risk. We measure our quality goal performance based on the performance appraisal of the members, as represented by the board of directors. Environmental compliance is measured by considering whether we have received notices of violation or letters of noncompliance, or had any spills at any of our facilities. Safety performance is measured by reviewing our standards and the safety of our work environment against those of other electric utilities. Corporate compliance is measured by considering whether we have received any violations under the Mandatory Electric Reliability Standard from North American Electric Reliability Corporation/Southeastern Electric Reliability Council. Future generation goal performance is measured based on the performance appraisal of our members, as represented by our board of directors. It is also measured by whether significant project milestones are met. These milestones are determined necessary in order for the project to remain on schedule for the planned commercial operation date.

Analysis of 2009 Compensation Paid to Executive Officers

As explained above, in identifying prevailing market compensation for similarly situated companies, we consider market data as well as achievement of corporate goals. In determining individual compensation for our executive officers, the compensation committee considers the total compensation awarded to each individual, and a percentage of each executive officer's annual compensation is based on corporate performance. This approach allows us to maintain the flexibility necessary to differentiate pay in recognition of corporate performance.

Executive officers' performance pay is based solely on the achievement of corporate goals. 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 the corporate goals identified above 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.

In 2009, our corporate goal achievement was 87.6%. Goal achievement rate by category based on the weighted system identified above was as follows:

Goal	Weighted Percentage
Operations	20.7%
Financial	23.0%
Quality	10.4%
Environmental Compliance	10.0%
Safety	5.0%
Corporate Compliance	1.0%
Future Generation	17.5%
Total	87.6%

We achieved 87.6% of our corporate goals for 2009 primarily because we met all of our financial, environmental compliance, safety and corporate compliance milestones. With respect to operations, the majority exceeded our threshold targets with most of these facilities achieving maximum targets. As a result of achieving 87.6% of our corporate goals for 2009, each of our executive officers received performance pay in an amount equal to 87.6% of 20% of his or her base salary. Set forth below is a table showing 2009 performance pay figures for each of our executive officers:

Executive Officer	Performance Pay*
Smith	$ 100,696
Price	$ 58,517
Higgins	$ 58,517
Ussery	$ 45,552
Robbins	$ 38,194

* Performance pay was calculated based on base salaries as of December 31, 2009. Actual compensation earned in 2009 is reported in the Summary Compensation Table below.

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, 2009 for filing with the SEC.

Respectfully Submitted,

The Compensation Committee
J. Sam L. Rabun
M. Anthony Ham
Larry N. Chadwick

Compensation Polices 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.

Compensation Committee Interlocks and Insider Participation

J. Sam L. Rabun, Gary A. Miller, Gary W. Wyatt, M. Anthony Ham and Larry N. Chadwick served as members of our compensation committee in 2009.

Gary A. Miller was a director of ours and the president and chief executive officer of GreyStone Power Corporation. GreyStone Power is a member of ours and has a wholesale power contract with us. GreyStone Power's payments of $76.6 million to us in 2009 under the wholesale power contract accounted for approximately 6.7% of our total revenues.

Gary W. Wyatt was a director of ours and was also the president and chief executive officer of Pataula Electric Membership Corporation. Pataula is a member of ours and has a wholesale power contract with us. Pataula's payments of $2.1 million to us in 2009 under the wholesale power contract accounted for less than 1% 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, 2009, 2008 and 2007.

Name and Principal Position	Year	Salary	Non-Equity Incentive Plan Compensation	All Other Compensation(1)	Total
Thomas A. Smith	2009	$ 570,625	$ 100,696	$ 91,557	$ 762,878
President and Chief Executive Officer	2008	537,500	94,270	74,439	706,209
	2007	469,313	77,425	68,332	615,070
Michael W. Price	2009	331,666	58,517	52,123	442,306
Executive Vice President, Chief Operating Officer	2008	305,208	54,848	48,496	408,552
	2007	275,853	45,640	57,261	378,754
Elizabeth B. Higgins	2009	331,666	58,517	51,786	441,969
Executive Vice President, Chief Financial Officer	2008	304,375	54,848	47,960	407,183
	2007	270,314	44,825	44,722	359,861
William F. Ussery	2009	258,333	45,552	44,003	347,888
Executive Vice President, Member and External Relations	2008	227,125	42,850	39,721	309,696
	2007	190,283	31,622	36,087	257,992
W. Clayton Robbins	2009	216,666	38,194	42,795	297,655
Senior Vice President, Governmental Affairs	2008	187,417	35,994	49,123	272,534
	2007	170,667	28,036	64,126	262,829

(1) Figures for 2009 consist of customary holiday gifts, 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. Robbins of $10,998, $11,025, $11,025, $9,097 and $10,976-, 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. Robbins 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. Robbins, respectively of $34,438, $11,321, $11,321, $4,495 and $114; 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. Robbins respectively; and insurance premiums paid on term life insurance on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Robbins of $3,870, $1,102, $765, $1,737, and $3,031, respectively.

We entered into an employment agreement with Thomas A. Smith, our president and chief executive officer, effective March 15, 2002. We entered into a restated employment agreement with Mr. Smith effective January 1, 2007. The original term of the employment agreement extended through December 31, 2009. Pursuant to the automatic renewal provision of the employment agreement, the current term of the agreement extends through December 31, 2012 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 the 2007 agreement is $440,870, and is subject to review and possible upward adjustment by our board of directors. Mr. Smith is eligible for an annual bonus or 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 2007 agreement. Mr. Smith's employment agreement contains severance pay provisions. Details regarding the severance pay provisions of the agreement are provided under " – Severance Arrangements."

Effective January 1, 2007, we entered into employment agreements with Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Robbins. The original term of each employment agreement extended through December 31, 2008. Pursuant to the automatic renewal provisions of the employment agreements, the current term of each agreement extends through December 31, 2011 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 the 2007 agreements are $255,116 for Mr. Price, $246,887 for Ms. Higgins, $171,700 for Mr. Ussery, and $164,000 for Mr. Robbins. Salaries are subject to review and possible upward adjustment as determined by the president and the chief executive officer. Each executive is also eligible for an annual bonus or 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. Robbins contain severance pay provisions. Details regarding the severance pay provisions of the agreements are provided under " – Severance Arrangements" below.

Grants of Plan-Based Award Table

The following table sets forth certain information with respect to the performance pay for the fiscal year ended December 31, 2009 awarded to the executive officers listed in the Summary Compensation Table.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards	
		Threshold[(1)]	Target[(2)]
Thomas A. Smith President and Chief Executive Officer	N/A	$ 25,864	$ 114,950
Michael W. Price Executive Vice President and Chief Operating Officer	N/A	15,030	66,800
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	N/A	15,030	66,800
William F. Ussery Executive Vice President, Member and External Relations	N/A	11,700	52,000
W. Clayton Robbins Senior Vice President, Governmental Affairs	N/A	9,810	43,600

(1) These figures represent the minimum amount each executive officer could receive under our 2009 performance pay program.

(2) These figures represent amounts payable to each executive officer if the specified performance targets under our 2009 performance pay program were reached.

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

Nonqualified Deferred Compensation

We maintain a Fidelity Non-Qualified Deferred Compensation Program. The 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). The following table sets forth our contributions for the fiscal year ended December 31, 2009 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	$ 34,438	$ 16,134	$ 104,594
Michael W. Price Executive Vice President and Chief Operating Officer	11,321	4,074	36,927
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	11,321	5,677	33,616
William F. Ussery Executive Vice President, Member and External Relations	4,495	755	7,629
W. Clayton Robbins Senior Vice President, Governmental Affairs	114	16	1,201

(1) All registrant contribution amounts shown have been included in the "All Other Compensation" column of the Summary Compensation Table above.

(2) A participant's account under the Fidelity Non-Qualified Deferred Compensation Program is invested in the investment options selected by the participant. The account is 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 Mr. Smith's employment without cause; or (2) Mr. Smith resigns due to a demotion or material reduction of his position or responsibilities, reduction of his base salary, or a relocation of Mr. Smith's 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 Mr. Smith's 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 $1,220,262.

Pursuant to the terms of their employment agreements, Mr. Price, Ms. Higgins, Mr. Ussery and Mr. Robbins 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. Robbins in the circumstances described above is $355,565, $355,693, $275,300 and $236,072, respectively.

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 W. Murphy is a director of ours and the President and Chief Executive Officer of Hart Electric Membership Corporation. Hart is a member of Oglethorpe and has a wholesale power contract with Oglethorpe. Hart's revenues of $20.8 million to Oglethorpe in 2009 under the wholesale power contract accounted for approximately 1.8% of our total revenues.

Gary A. Miller was a director of ours through March 2009 and he is the President and Chief Executive Officer of GreyStone Power Corporation. GreyStone is a member of Oglethorpe and has a wholesale power contract with Oglethorpe. GreyStone's revenues of $76.6 million to Oglethorpe in 2009 under the wholesale power contract accounted for approximately 6.7% of our total revenues.

C. Hill Bentley is a director of ours and the Chief Executive Officer of Tri-County Electric Membership Corporation. Tri-County is a member of Oglethorpe and has a wholesale power contract with Oglethorpe. Tri-County's revenues of $12.9 million to Oglethorpe in 2009 under the wholesale power contract accounted for approximately 1.1% of our total revenues.

Gary W. Wyatt was a director of ours through January 2010 and was also the President and Chief Executive Officer of Pataula Electric Membership Corporation. Pataula is a member of Oglethorpe and has a wholesale power contract with Oglethorpe. Pataula's revenues of $2.1 million to Oglethorpe in 2009 under the wholesale power contract accounted for less than 0.2% of our total revenues and Pataula is owned by another member of Oglethorpe, Cobb Electric Membership Corporation.

Rick Gaston is a director of ours and the General Manager of Colquitt Electric Membership Corporation. Colquitt is a member of Oglethorpe and has a wholesale power contract with Oglethorpe. Colquitt's revenues of $34.0 million to Oglethorpe in 2009 under the wholesale power contract accounted for approximately 3.0% 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 Oglethorpe and has a wholesale power contract with Oglethorpe. Jackson's revenues of $132.3 million to Oglethorpe in 2009 under the wholesale power contract accounted for approximately 11.6% 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 Gary A. Miller, whose term expired on March 31, 2009, and 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. Gary A. Miller did not qualify as an independent director because he is the President and Chief Executive Officer of GreyStone Power, which accounted for approximately 6.7% of our revenues for the fiscal year ended December 31, 2009. Randall Pugh also does not qualify as an independent director because he is the President and Chief Executive Officer of Jackson, which accounted for approximately 11.6% of our revenues for the fiscal year ended December 31, 2009. Although we do not have any securities listed on the NASDAQ Stock Market, we have used the NASDAQ Stock Market's independence criteria in making this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For 2009 and 2008, fees for services provided by our independent registered public accounting firm, PricewaterhouseCoopers LLP were as follows:

	(dollars in thousands)	
	2009	2008
Audit Fees(1)	**$ 793**	$ 421
Tax Fees(2)	**24**	23
Audit-Related Fees(3)	**6**	154
Total	**$ 823**	$ 598

(1) Audit of annual financial statements and review of financial statements included in SEC filings and services rendered in connection with financings.

(2) Professional tax services including tax consultation and tax return preparation.

(3) Audit related services rendered in connection with future Section 404 compliance requirements.

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 Pricewaterhouse Coopers LLP in 2009 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.

Change in Independent Registered Public Accounting Firm

In July 2009, we selected Ernst & Young LLP as our new independent public accounting firm to audit our consolidated financial statements for the fiscal year ending December 31, 2010. PricewaterhouseCoopers LLP acted as our independent registered public accounting firm until the completion of its procedures related to our consolidated financial statements for the fiscal year ended December 31, 2009 and the filing of this annual report on Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of Documents Filed as a Part of This Report.

		Page
(1)	Financial Statements (Included under "Financial Statements and Supplementary Data")	62
	Consolidated Statements of Revenues and Expenses, For the Years Ended December 31, 2009, 2008 and 2007	63
	Consolidated Balance Sheets, As of December 31, 2009 and 2008	64
	Consolidated Statements of Capitalization, As of December 31, 2009 and 2008	66
	Consolidated Statements of Cash Flows, For the Years Ended December 31, 2009, 2008 and 2007	67
	Consolidated Statements of Patronage Capital and Membership Fees And Accumulated Other Comprehensive Deficit, For the Years Ended December 31, 2009, 2008 and 2007	68
	Notes to Consolidated Financial Statements	69
	Report of Independent Registered Public Accounting Firm	94

(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. (Filed as Exhibit 3.2 to the Registrant's Form 8-K, filed May 5, 2008, File No. 33-7591.)
*4.1	–	Form of Serial Facility Bond Due June 30, 2011 (included in Collateral Trust Indenture filed as Exhibit 4.2.)
*4.2	–	Collateral Trust Indenture, dated as of December 1, 1997, between OPC Scherer 1997 Funding Corporation A, Oglethorpe and SunTrust Bank, Atlanta, as Trustee. (Filed as Exhibit 4.2 to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*4.3	–	Nonrecourse Promissory Lessor Note No. 2, with a Schedule identifying three other substantially identical Nonrecourse Promissory Lessor Notes and any material differences. (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)

*4.4	–	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.)
*4.5(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.)
*4.5(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)).
*4.5(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.)
*4.5(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.)
*4.6	–	Fifth Amended and Restated Loan Contract, dated as of December 22, 2008, between Oglethorpe and the United States of America, together with two notes executed and delivered pursuant thereto. (Filed as Exhibit 4.6 to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)

*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)

*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)

*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)

*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)
*4.7.1(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.)

*4.7.1(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.)
*4.7.1(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.)
4.7.1(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.
4.7.1(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.
4.7.1(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).
*4.7.2	–	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.)
4.8.1[(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.
4.8.2[(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.
4.8.3[(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.
4.9.1[(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.
4.9.2[(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.

4.9.3[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.
4.10.1[1]	–	Loan Agreement, dated as of October 1, 2006, 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 2006B, and fifteen other substantially identical (Term Rate Bonds) loan agreements.
4.10.2[1]	–	Note, dated as of October 24, 2006, from Oglethorpe to U.S. Bank National Association, as trustee, pursuant to a Trust Indenture, dated as of October 1, 2006, 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 2006B, and fifteen other substantially identical notes.
4.10.3[1]	–	Trust Indenture, dated as October 1, 2006, 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 2006B, and fifteen other substantially identical indentures.
4.11.1[1]	–	Loan Agreement, dated as of December 1, 2009, 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 2009A, and two other substantially identical (Variable Rate Bonds) loan agreements.
4.11.2[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 two other substantially identical notes.
4.11.3[1]	–	Trust Indenture, dated as of 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 two other substantially identical indentures.
*4.12.1	–	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.)
*4.12.2	–	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.)
4.13.1[1]	–	Master Loan Agreement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, MLA No. 0459.
4.13.2[1]	–	Consolidating Supplement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, relating to Loan No. ML0459T1.
4.13.3[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.

4.13.4[1]	–	Consolidating Supplement, dated as of March 1, 1997, between Oglethorpe and CoBank, ACB, relating to Loan No. ML0459T2.
4.13.5[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.
4.14.1[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.
4.14.2[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.
4.14.3[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.
4.14.4[1]	–	Series 2009C CFC Note, dated August 11, 2009, in the original principal amount of $250,000,000 from Oglethorpe Power to National Rural Utilities Cooperative Finance Corporation.
4.15.1[1]	–	Credit Agreement, dated as of November 30, 2009, between Oglethorpe and CoBank, ACB, relating to the Series 2009A CoBank Note.
4.15.2[1]	–	Series 2009A CoBank Note, dated November 30, 2009, in the original principal amount of $150,000,000, made by Oglethorpe to CoBank, ACB.
4.16.1[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).
4.16.2[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.)
*10.5.1	–	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.
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.
*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, Filed 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 s 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(1)	–	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(2)	–	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(1)	–	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(2)	–	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[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.)
*10.17[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.)

*10.18[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.)
*10.19[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.)
*10.20[3]	–	Employment Agreement, dated as of January 1, 2007, between Oglethorpe and William Clay Robbins. (Filed as Exhibit 10.24 to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*10.21	–	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.)
*10.22	–	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.)
*14.1	–	Code of Ethics, revised July 10, 2008. (Filed as Exhibit 14.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2008, File No. 33-7591.)
21.1	–	Subsidiaries of the Registrant and jurisdiction of incorporation/organization: Rocky Mountain Leasing Corporation, a Delaware corporation.
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, 2009, File No. 33-7591.)

(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 22nd day of March, 2010.

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 22, 2010
/s/ ELIZABETH B. HIGGINS ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 22, 2010
/s/ BRIAN PREVOST BRIAN PREVOST	Vice President, Controller (Chief Accounting Officer)	March 22, 2010
/s/ C. HILL BENTLEY C. HILL BENTLEY	Director	March 22, 2010
/s/ LARRY N. CHADWICK LARRY N. CHADWICK	Director	March 22, 2010
/s/ BENNY W. DENHAM BENNY W. DENHAM	Director	March 22, 2010
/s/ WM. RONALD DUFFEY WM. RONALD DUFFEY	Director	March 22, 2010
/s/ RICK L. GASTON RICK L. GASTON	Director	March 22, 2010

Signature	Title	Date
/s/ M. ANTHONY HAM M. ANTHONY HAM	Director	March 22, 2010
/s/ MARSHALL MILLWOOD MARSHALL MILLWOOD	Director	March 22, 2010
/s/ JEFFREY W. MURPHY JEFFREY W. MURPHY	Director	March 22, 2010
/s/ G. RANDALL PUGH G. RANDALL PUGH	Director	March 22, 2010
/s/ J. SAM L. RABUN J. SAM L. RABUN	Director	March 22, 2010
/s/ BOBBY C. SMITH, JR. BOBBY C. SMITH, JR.	Director	March 22, 2010
/s/ H. B. WILEY, JR. H. B. WILEY, JR.	Director	March 22, 2010