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, 2016

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 ✓ 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

2016 FORM 10-K ANNUAL REPORT

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains "forward-looking statements." All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as the timing of various regulatory and other actions, future capital expenditures, business strategy and development, construction or operation of facilities (often, but not always, identified through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "projection," "target" and "outlook") are forward-looking statements.

Although we believe that in making these forward-looking statements our expectations are based on reasonable assumptions, any forward-looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward-looking statements. Some of the risks, uncertainties and assumptions that may cause actual results to differ from these forward-looking statements are described under the heading "RISK FACTORS" and in other sections of this annual report. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this annual report may not occur.

Any forward-looking statement speaks only as of the date of this annual report, and, except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of them; nor can we assess the impact of each factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- cost increases and schedule delays with respect to our capital improvement and construction projects, in particular, the construction of two additional nuclear units at Plant Vogtle;
- our access to capital, the cost to access capital, and the results of our financing and refinancing efforts, including availability of funds in the capital markets;
- uncertainty as to our continued eligibility to receive advances from the U.S. Department of Energy for construction of two additional nuclear units at Plant Vogtle and the continued availability of funding from the Rural Utilities Service;
- the impact of regulatory or legislative responses to climate change initiatives or efforts to reduce greenhouse gas emissions, including carbon dioxide;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- increasing debt caused by significant capital expenditures;
- actions by credit rating agencies;
- commercial banking and financial market conditions;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;
- adequate funding of our nuclear decommissioning trust funds including investment performance and projected decommissioning costs;
- continued efficient operation of our generation facilities by us and third-parties;
- the availability of an adequate and economical supply of fuel, water and other materials;
- reliance on third-parties to efficiently manage, distribute and deliver generated electricity;
- acts of sabotage, wars or terrorist activities, including cyber attacks;

- the inability of counterparties to meet their obligations to us, including failure to perform under agreements;
- litigation or legal and administrative proceedings and settlements;
- changes in technology available to and utilized by us, our competitors, or residential or commercial consumers in our members' service territories, including from the development and deployment of distributed generation and energy storage technologies;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption, energy conservation and efficiency efforts and the general economy;
- our members' ability to perform their obligations to us;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- general economic conditions;
- weather conditions and other natural phenomena;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- significant changes in critical accounting policies material to us; and
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards.

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 38 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 one of the largest electric cooperatives in the United States in terms of revenues, 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 278 employees.

Our members are local consumer-owned distribution cooperatives that provide retail electric service on a not-for-profit basis. In general, our members' customer base consists of residential, commercial and industrial consumers within specific geographic areas. Our members serve approximately 1.9 million electric consumers (meters) representing approximately 4.1 million people. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES."

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

Cooperative Principles

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

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. See "– First Mortgage Indenture."

Power Supply Business

We provide wholesale electric service to our members for nearly two-thirds of their aggregate power requirements primarily from our fleet of generation assets but also with power purchased from other power suppliers. We provide this service pursuant to long-term, take-or-pay wholesale power contracts. The wholesale power contracts obligate our members jointly and severally to pay rates sufficient for us to recover all the costs of owning and operating our power supply business, including the payment of principal and interest on our indebtedness and to yield a minimum 1.10 margins for interest ratio under our first mortgage indenture. Our members satisfy all of their power requirements above their purchase obligations to us with purchases from other suppliers. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Our fleet of generating units total 7,809 megawatts of summer planning reserve capacity, which includes 728 megawatts of Smarr EMC assets that we manage but do not own. Our generation portfolio includes units powered by nuclear, gas, coal, oil and water. See "OUR POWER SUPPLY RESOURCES," "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Smarr EMC*" and "PROPERTIES – Generating Facilities."

In 2016, three of our members, Jackson EMC, Cobb EMC and Sawnee EMC, accounted for 14.3%, 13.7% and 10.5% of our total revenues, respectively. Each of our other members accounted for less than 10% of our total revenues in 2016.

Wholesale Power Contracts

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

We have assigned fixed percentage capacity cost responsibilities to our members for all of our generation and purchased power resources, although not all members participate in all resources. For any future resource, we will assign fixed percentage capacity cost responsibilities only to members choosing to participate in that resource. The wholesale power contracts provide that each member is jointly and severally responsible for all costs and expenses of all existing generation and purchased power resources, as well as for approved future resources, whether or not that member has elected to participate in the resource, that are approved by 75% of the members of our board of directors, 75% of our members and members representing 75% of our patronage capital. 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.

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 2016, we supplied energy that accounted for approximately 64% 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 periodically 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.

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

Under the first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates which are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. The formulary rate 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. In the event we were to fall short of the minimum 1.10 margins for interest ratio at year end, the formulary rate is designed to recover the shortfall from our members in the following year without any additional action by our board of directors.

Under our loan agreements with each of the Rural Utilities Service and Department of Energy, changes to our rates resulting from adjustments in our annual budget are generally not subject to their approval. We must provide the Rural Utilities Service and Department of Energy with a notice of and opportunity to object to most changes to the formulary rate under the wholesale power contracts. See "– Relationship with Federal Lenders." Currently, our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

First Mortgage Indenture

Our principal financial requirements are contained in the Indenture, dated as of March 1, 1997, from us to U.S. Bank National Association, as trustee (successor to SunTrust Bank), as amended and supplemented, referred to herein as the first mortgage indenture. The first mortgage indenture constitutes a lien on substantially all of our owned tangible and certain of our intangible property, including property we acquire in the future. The mortgaged property includes our owned electric generating plants, the wholesale power contracts with our members and some of our contracts relating to the ownership, operation or maintenance of electric generation facilities owned by us.

Under our first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates which are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. The margins for interest ratio is determined by dividing margins for interest by total interest charges on debt secured under our first mortgage indenture. Margins for interest is the sum of:

- our net margins (after certain defined adjustments), plus
- interest charges on all indebtedness secured under our first mortgage indenture, plus
- any amount included in net margins for accruals for federal or state income taxes.

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. 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 Corporation.

Under our first mortgage indenture, we are prohibited from making any distribution of patronage capital to our members if, at the time of or after giving effect to the distribution, (i) an event of default exists under the first mortgage indenture, (ii) our equity as of the end of the immediately preceding fiscal quarter is less than 20% of our total long-term debt and equities, or (iii) the aggregate amount expended for distributions on or after the date on which our equity first reaches 20% of our total long-term debt and equities exceeds 35% of our aggregate net margins earned after such date. This last restriction, however, will not apply if, after giving effect to such distribution, our equity as of the end of the immediately preceding fiscal quarter is at least 30% of our total long-term debt and equities. As of December 31, 2016, our equity ratio was 9.3%.

As of December 31, 2016, we had approximately $8.3 billion of secured indebtedness outstanding under the first mortgage indenture. From time to time, we may issue additional first mortgage obligations ranking equally and ratably with the existing first mortgage indenture obligations. The aggregate principal amount of obligations that may be issued under the first mortgage indenture is not limited; however, our ability to issue additional obligations under the first mortgage indenture is subject to certain requirements related to the certified value of certain of our tangible property, repayment of obligations outstanding under the first mortgage indenture and payments made under certain pledged contracts relating to property to be acquired.

Relationship with Federal Lenders

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, Rural Utilities Service loan funds are subject to annual federal budget appropriations, and, due to budgetary and political pressures faced by Congress, the availability and magnitude of these loan funds cannot be assured. Congress has authorized the Rural Utilities Service to charge a fee to cover the cost of loan guarantees for baseload generation, if requested by a borrower. The Rural Utilities Service must establish a process to implement this authorization prior to making it available to borrowers. The fiscal year 2016 loan program level of $5.5 billion has been continued through April 2017. The President's very high level budget blueprint for fiscal year 2018, which begins October 2017, issued March 16, 2017, does not contain any information regarding this loan program, including any potential changes to it. Although Congress has historically rejected proposals to dramatically curtail or redirect 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 loans that may be available to us in the future.

We have a loan contract with the Rural Utilities Service. Under the loan contract, we may have to obtain approval from the Rural Utilities Service or provide the Rural Utilities Service with a notice and an opportunity to object before we take certain actions, 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 formulary rate contained in the wholesale power contracts, and
- changes to plant ownership and operating agreements.

As of December 31, 2016, we had $2.6 billion of outstanding loans guaranteed by the Rural Utilities Service and secured under our first mortgage indenture.

Department of Energy

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005, we entered into a loan guarantee agreement with the Department of Energy in 2014, pursuant to which the Department of Energy agreed to guarantee our obligations under a multi-advance term loan facility with the Federal Financing Bank.

Proceeds of advances made under the facility will be used to reimburse us for a portion of certain costs of construction relating to two additional nuclear units at Plant Vogtle that are eligible for financing under the Title XVII Loan Guarantee Program. We may make advances under the facility until December 31, 2020 and aggregate borrowings under the facility may not exceed $3.1 billion of eligible project costs.

Under this loan guarantee agreement, we may have to obtain approval from the Department of Energy or provide the Department of Energy with a notice and opportunity to object before we take certain actions, including, without limitation,

- significant dispositions of system assets, including the transfer of our undivided ownership interest in Vogtle Units No. 3 and No. 4 prior to commercial operation of both units,
- changes to the wholesale power contracts and the formulary rate contained in the wholesale power contracts,
- certain changes to plant ownership and operating agreements relating to Vogtle Units No. 3 and No. 4, and
- agreeing to the removal or replacement of Georgia Power Company or Southern Nuclear Operating Company, Inc. in their respective roles as agents for the Co-owners in connection with the additional Vogtle units.

As of December 31, 2016, we had advanced $1.7 billion under this loan. All advances made under this facility are secured under our first mortgage indenture. For additional information regarding the loan guarantee agreement, including conditions to future advances and alternate amortization events, see Note 7a of Notes to Consolidated Financial Statements. For additional information on Vogtle Units No. 3 and No. 4, see "– OUR POWER SUPPLY RESOURCES – Future Power Resources – *Vogtle Units No. 3 and No. 4*."

Relationship with Georgia Transmission Corporation

We and our 38 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.

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

We currently have approximately $11.2 million of loans outstanding to Georgia System Operations, primarily for the purpose of financing capital expenditures. Georgia System Operations has an additional $10.0 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 Georgia Power Company

Our relationship with Georgia Power is a significant factor in several aspects of our business. Except for the Rocky Mountain Pumped Storage Hydroelectric Facility, Georgia Power, on behalf of itself as a co-owner and as agent for the other co-owners, is responsible for the construction and operation of all our co-owned generating facilities, including the development and construction of Vogtle Units No. 3 and No. 4. 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."

Relationship with Smarr EMC

Smarr EMC is a Georgia electric membership corporation owned by 35 of our 38 members. Smarr EMC owns two combustion turbine facilities with aggregate capacity of 728 megawatts. We provide operations, financial and management services for Smarr EMC. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

Relationship to Green Power EMC

Green Power Electric Membership Corporation, owned by our 38 members, is a power supply cooperative specializing in the purchase of renewable energy for its members. The members purchase small quantities of energy from Green Power EMC. We supply management services to Green Power EMC. See "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources."

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 operate in 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 which would amend the Georgia Territorial Act or otherwise affect the exclusive right of our members to supply power to their current service territories. However, parties have unsuccessfully sought and will likely continue to seek to advance legislative proposals that will directly or indirectly affect the Georgia Territorial Act in order to allow increased retail competition in our members' service territories. The Georgia Public Service Commission does not have the authority under Georgia law to order retail competition or amend the Georgia Territorial Act. We cannot predict at this time the outcome of various developments that may lead to increased competition in the electric utility industry or the effect of any developments on us or our members.

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

- power marketing arrangements or other alliance arrangements;
- adjusting the mix of ownership and purchase arrangements used to meet power supply requirements;
- construction or acquisition of power supply resources, whether owned by us or by other entities;
- use of power purchase contracts to meet power supply requirements, and whether to use short, medium or long-term contracts, or a mix of terms;

- participation in future power supply resources developed by others, whether by ownership or long-term purchase commitment;
- whether disposition of existing assets or asset classes would be advisable;
- maturity extensions of existing indebtedness;
- potential prepayment of debt;
- various responses to the proliferation of non-core services offered by electric utilities;
- mergers or other combinations with distributors or power suppliers; and
- other changes in our businesses intended to take advantage of current and anticipated trends in the electric industry.

We will continue to consider industry trends and developments, but cannot predict the outcome 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 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, the Clean Power Plan includes individual state goals for carbon dioxide emissions. Our greenhouse gas emissions are significant, but we also have generation sources that emit no greenhouse gases. Some of our competitors use sources that emit proportionately more greenhouse gases, while the sources of some competitors emit less. Further, third-party suppliers to our members are relying on generation sources that emit greenhouse gases. The terms and conditions in 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 these suppliers. We believe our and our members' diverse portfolios of generation facilities, including the diversity of third-party suppliers, would mitigate any impact on our and our members' competitiveness resulting from these regulations. See "REGULATION – Environmental – *Carbon Dioxide Emissions and Climate Change*" and "RISK FACTORS."

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

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

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

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

Seasonal Variations

Our members' demand for energy is influenced by seasonal weather conditions. Historically, higher demand has occurred during summer and winter months than in spring and fall months. Even so, summer and winter demand historically has been lower when weather conditions are milder and higher when weather conditions are more extreme. A variety of factors affect our members' decisions whether to purchase their increased seasonal demand from us. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION – Results of Operations – *Factors Affecting Results*." 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 cannot make accurate conclusions about seasonality related to changes in weather patterns. Our energy revenues recover 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 fleet of generating assets and power purchased from other suppliers. In 2016, we supplied approximately 64% of the retail energy requirements of our members.

Generating Plants

Our fleet of generating units total 7,809 megawatts of summer planning reserve capacity, including 728 megawatts of Smarr EMC assets, which we manage. This generation portfolio includes our interests in units fueled by nuclear, coal, gas, oil and water. Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton also have interests in nine of these units at Plants Hatch, Vogtle, Wansley and Scherer. Georgia Power serves as operating agent for these nine units. Georgia Power also has an interest in the three units at Rocky Mountain, which we operate. In addition to our 31 generating units, we operate and manage six gas-fired generating units on behalf of Smarr EMC.

See "PROPERTIES" for a description of our generating facilities, fuel supply and the co-ownership arrangements. For a description of Smarr EMC's assets, see "OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Smarr EMC*."

Power Purchase and Sale Arrangements

We currently have no material power purchase or sale 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 2016, 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.

We have interchange, transmission and/or short-term capacity and energy purchase or sale agreements with a number of 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.

Future Power Resources

Plant Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Our binding ownership interest and proportionate share of the cost to construct these units is 30%. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company as its agent for licensing, engineering, procurement, contract management, construction and pre-operation services.

In 2008, Georgia Power, acting for itself and as agent for the Co-owners, entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, the Contractor). Stone & Webster was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. Pursuant to the EPC Agreement, the Contractor agreed to design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle.

Under the EPC Agreement, the Co-owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders and performance bonuses. The EPC Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to a cap of 10% of the contract price, or approximately $920 to $930 million. In addition, the EPC Agreement provides for limited cost sharing by the Co-owners for increases to Contractor costs under certain conditions. The maximum amount of additional capital costs under this provision attributable to us is $75 million. Each Co-owner is severally, not jointly, liable to the Contractor for its proportionate share, based on ownership interest, of all amounts owed under the EPC Agreement. In the event of certain credit rating downgrades of any Co-owner, such Co-owner will be required to provide a letter of credit or other credit enhancement.

Under the terms of the EPC Agreement, the Contractor does not have the right to terminate the EPC Agreement for convenience. The Contractor may terminate the EPC Agreement under certain circumstances, including certain suspension or delays of work by the Co-owners, action by a governmental authority to stop work permanently, certain breaches of the EPC Agreement by the Co-owners, Co-owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the EPC Agreement is increased significantly but remains subject to limitations. The EPC Agreement permits Georgia Power, acting for itself and as agent for the Co-owners, to terminate the EPC Agreement at any time for their convenience, provided that the Co-owners will be required to pay certain termination costs.

Certain obligations of Westinghouse under the EPC Agreement, including, but not limited to, liquidated damages and damages related to abandoning the Vogtle project, have been guaranteed by Toshiba Corporation, Westinghouse's parent company. In January 2016, as a result of credit rating downgrades of Toshiba, Westinghouse provided the Co-owners with $920 million of letters of credit pursuant to the terms of the EPC Agreement. These letters of credit remain in place in accordance with the terms of the EPC Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a goodwill impairment charge of over $6 billion at Westinghouse primarily attributable to the increased cost estimates to complete its nuclear projects in the United States, including Vogtle Units No. 3 and No. 4. As a result of the charge, Toshiba warned that it will likely be in a negative equity position which has created significant uncertainty regarding potential actions Toshiba may take to address this situation. At that time, Toshiba reaffirmed its commitment to its nuclear projects in the United States with implementation of management changes and increased oversight. However, since that initial announcement, Westinghouse has engaged legal and financial bankruptcy advisors and is soliciting debtor-in-possession financing packages, significantly increasing the likelihood that Westinghouse will file bankruptcy in the near-term. We are also aware that some subcontractors have asserted that the Contractor has not made payments for work performed at the Vogtle project. Georgia Power, on behalf of the Co-owners, and we are analyzing potential contingency planning scenarios and have retained legal and financial advisors in the event the Contractor fails to remedy any payment deficiencies or Westinghouse files for bankruptcy protection. A failure by Westinghouse or Toshiba to perform its obligations, including as a result of a declaration of bankruptcy by either or both of Westinghouse and Toshiba, under the EPC Agreement or the related Toshiba parent guarantee, respectively, could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4.

In February 2017, the Contractor also provided Georgia Power, as agent for the Co-owners, with a preliminary schedule for revised forecasted in-service dates of December 2019 for Unit No. 3 and September 2020 for Unit No. 4, delays of six months and three months from the prior forecasted in-service dates of June 2019 and June 2020, respectively. The Contractor, Georgia Power and other Co-owners are continuing to review the schedule supporting these revised dates which must ultimately be reconciled with an integrated project schedule. Based on this continued schedule verification, at this time, we believe that the revised in-service dates of December 2019 and September 2020 do not appear to be achievable. To the extent that the Contractor is unable to meet the current revised forecasted in-service dates, such delay could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4. We believe the Contractor is responsible for any related costs for not achieving the schedule and performance guarantees in the EPC Agreement. The EPC Agreement provides that the Contractor will begin to incur delay liquidated damages if the nuclear fuel loading dates for Unit No. 3 and No. 4 go beyond December 31, 2018 and December 31, 2019, respectively.

Our project budget for Vogtle Units No. 3 and No. 4, which includes capital costs and allowance for funds used during construction, is currently $5.0 billion. As of December 31, 2016, our total investment in the additional Vogtle units was $3.3 billion. Although many factors could increase our project budget, we do not anticipate that the announced six and three month delays to the forecasted in-service dates for Units No. 3 and No. 4, respectively, will change our current project budget. In the event the Contractor is unable to meet the revised forecasted in-service dates, we anticipate that each month of additional delay in the near-term will cost us approximately $20 million, including financing and owner's costs, net of liquidated damages. Further, the failure of Westinghouse or Toshiba to perform its obligations under the EPC Agreement or the related Toshiba parent guarantee, respectively, could have a material impact on the cost and schedule of Vogtle Units No. 3 and No. 4 and could significantly impact our project budget.

We have a $3.1 billion federal loan guarantee from the Department of Energy, under which we have advanced $1.7 billion as of December 31, 2016. We have also financed an additional $1.4 billion of the capital costs of the Vogtle units through capital market debt issuances. A failure by the Contractor to perform its obligations under the EPC Agreement could, under certain circumstances, impact our ability to make further advances under the Department of Energy-guaranteed loan and give the Department of Energy discretion to require that we repay all amounts outstanding under the loan guarantee agreement over a five-year period. For additional information regarding the financing of Vogtle Units No. 3 and No. 4, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *Financing Activities – Department of Energy-Guaranteed Loan" and "– Capital Requirements – Capital Expenditures,"* and for additional information regarding applicable covenants, events of default and potential alternate amortization events under the loan guarantee agreement with the Department of Energy, see Note 7a of Notes to Consolidated Financial Statements.

Substantial risks remain that continued challenges with the Contractor's construction performance, including labor productivity, fabrication, delivery, assembly and installation of plant systems, structures and components, or other issues could further impact the project schedule and cost. In addition, there have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state levels, and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse AP1000 Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the Nuclear Regulatory Commission. Further, various design and other licensing-based compliance matters, including the timely resolution of inspections, tests, analyses and acceptance criteria by the Nuclear Regulatory Commission may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners, the Contractor, or both.

Future claims by the Contractor or Georgia Power, on behalf of the Co-owners, could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the EPC Agreement and may be resolved through litigation after the completion of nuclear fuel load for both units. The failure of Westinghouse or Toshiba to fulfill its obligations under the EPC Agreement or the related Toshiba parent guarantee, respectively, as a result of a bankruptcy filing would also be expected to lead to litigation and we would expect Georgia Power, on behalf of the Co-Owners, to aggressively pursue and seek to enforce all potential Co-owner rights and remedies.

Despite the uncertainty surrounding the EPC Agreement and the financial health of Westinghouse and Toshiba, at this time we remain committed to continuing to work on the Vogtle project. We will continue to monitor and evaluate developments related to the Vogtle project and will endeavor to undertake a course of action that we believe will advance the long-term interests of our members. Georgia Power has stated that it is prepared to take appropriate actions on behalf of the Co-owners should Westinghouse or Toshiba fail to perform its obligations under the EPC

Agreement and the related Toshiba parent guarantee, respectively.

The ultimate outcome of these matters cannot be determined at this time. See "RISK FACTORS" for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units.

Other Future Power Resources

From time to time, we may assist our members in investigating potential new power supply resources, after compliance with the terms of the New Business Model Member Agreement. See "OGLETHORPE POWER CORPORATION – New Business Model Member Agreement."

OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES

Member Demand and Energy Requirements

Our members are listed below and include 38 of the 41 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
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 1.9 million electric consumers (meters) representing approximately 4.1 million people. Our members serve a region covering approximately 38,000 square miles, which is approximately 65% of the land area in the State of Georgia, encompassing 151 of the State's 159 counties. Historically, our members' sales by customer class have been approximately two-thirds to residential consumers and slightly less than one-third to commercial and industrial consumers. Our members are the principal suppliers for the power needs of rural Georgia. While our members do not serve any major cities, portions of their service territories are in close proximity to urban areas and have experienced substantial growth over the years due to the expansion of urban areas, including metropolitan Atlanta, into suburban areas and the growth of suburban areas into neighboring rural areas. Each year we file with one of our quarterly reports on Form 10-Q an exhibit containing financial and statistical information for our 38 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 2014 through 2016, and also shows the amount of their energy requirements that we supplied. From 2014 through 2016, peak demand of the members decreased at an average annual compound rate of 0.9% and energy requirements increased at an average annual compound rate of 1.4%. In 2016, the amount of energy we supplied to the members increased nearly 40% primarily as a result of the availability of the Smith Energy Facility to meet the members' energy requirements, as well as an increase in total member requirements.

	Member Peak Demand (MW)	Member Energy Requirements (MWh)	
	Total(1)	Total(2)	Supplied by Oglethorpe(3)
2016	9,194	39,668,000	25,522,852
2015	8,964	38,323,141	18,371,558
2014	9,354	38,590,467	20,154,108

(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 in 2014 or 2015 but began supplying energy to Flint in 2016. Also includes energy we supplied to our own facilities.

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. Parties have unsuccessfully sought and will likely continue to seek to advance legislative proposals that will directly or indirectly affect the Georgia Territorial Act in order to allow increased retail competition in our members' service territories.

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 the premises 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 members' 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% of total assets. See "– Members' Relationship with the Rural Utilities Service."

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

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

Rate Regulation of Members

Through provisions in the loan documents securing loans to the members, the Rural Utilities Service exercises control and supervision over the rates for the sale of power of our members that borrow from it. The Rural Utilities Service mortgage indentures of these members require them to design rates with a view to maintaining an average times interest earned ratio and an average debt service coverage ratio of not less than 1.25 and an operating times interest earned ratio and an operating debt service coverage ratio of not less than 1.10, in each case for the two highest out of every three successive years.

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

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

Members' Relationship with the Rural Utilities Service

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

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

The fiscal year 2016 loan program level of $5.5 billion has been continued through April 2017. The President's very high level budget blueprint for fiscal year 2018, which begins October 2017, issued March 16, 2017, does not contain any information regarding this loan program, including any potential changes to it. Although Congress has historically rejected proposals to dramatically curtail or redirect 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 loans that may be available to the members in the future. For additional information regarding the Rural Utilities Service, see "OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders – *Rural Utilities Service*."

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 would otherwise incur. Under the member transmission service agreements, members have the right to design, construct and own new distribution substations.

Georgia System Operations has contracts with each of its members, including Georgia Transmission and us, to provide to them the services that it in turn purchases from Georgia Power under the Control Area Compact, which we co-signed with Georgia System Operations.

Georgia System Operations also provides operation services for the benefit of our members through agreements with us, including dispatch of our resources and other power supply resources owned by the members.

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

Member Power Supply Resources

Oglethorpe Power Corporation

In 2016, we supplied approximately 64% of the retail energy requirements of our members. Pursuant to the wholesale power contracts, we supply each member energy from our generation resources based on its fixed percentage capacity cost responsibility, which are take-or-pay obligations. See ''OGLETHORPE POWER CORPORATION – Wholesale Power Contracts.'' Our members satisfy all of their requirements above their purchase obligations to us with purchases from other suppliers as described below.

Contracts with Southeastern Power Administration

Our members purchase hydroelectric power from the Southeastern Power Administration, or SEPA, under contracts that originally extended through 2016 and will continue until terminated by two years' written notice by SEPA or the respective member. In 2016, 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, 37 of our members' SEPA power deliveries. Further, each member may be required, if certain conditions are met, to contribute funds for capital improvements for U.S. Army Corps of Engineers projects from which its allocation is derived in order to retain the allocation.

Smarr EMC

Smarr EMC is a Georgia electric membership corporation owned by 35 of our 38 members. Smarr EMC owns two combustion turbine facilities with aggregate capacity of 728 megawatts. The 35 members participating in these two facilities purchase the output of those facilities pursuant to separate take-or-pay power purchase agreements with initial terms that extended through 2014 and 2015, respectively, and will continue until terminated by one year's written notice by Smarr EMC or the respective member.

Green Power EMC

Each of our members is also a member of Green Power Electric Membership Corporation, a power supply cooperative specializing in the purchase of renewable energy for its members. Green Power EMC currently purchases energy from 112 megawatts of low-impact hydroelectric, landfill gas, wood-waste biomass and solar facilities, with plans to purchase more in the future.

Georgia Energy Cooperative

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

Other Member Resources

Our members obtain their remaining power supply requirements from various sources. Thirty-one members are parties to requirements contracts with third parties for some or all of their incremental power needs. The other members use a portfolio of short-term and long-term power purchase contracts to meet their incremental requirements. These requirements contracts and long-term power purchase contracts have remaining terms ranging from 6 to 25 years.

These other purchases include 151 megawatts from solar facilities under 25-year contracts.

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

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

REGULATION

Environmental

General

As an electric utility, we are subject to various federal, state and local environmental laws. Air emissions, water discharges and water usage are extensively controlled, closely monitored and periodically reported. The manner in which various types of wastes can be stored, transported and disposed is also broadly regulated.

In general, environmental requirements are becoming increasingly stringent. Although we have installed environmental control systems at our plants to ensure continued compliance with existing requirements, including systems to reduce emissions of sulfur dioxide, nitrogen oxides, mercury and other pollutants at Plants Scherer and Wansley, new requirements could be imposed. Such requirements may substantially increase the cost of electric service, by requiring modifications in the design or operation of existing facilities. Failure to comply with these requirements could result in civil and criminal penalties and could include 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 and 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.

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

Air Quality

Environmental concerns of the public, the scientific community and government officials have resulted in legislation and regulation that has had and will continue to have a significant impact on the entire electric utility industry. The most significant environmental legislation for us continues to be the Clean Air Act, which regulates emissions of sulfur dioxide, nitrogen oxides, particulate matter, greenhouse gases and other pollutants from affected electric utility units, including the coal-fired units at Plants Scherer and Wansley. The Environmental Protection Agency, or EPA, has been actively regulating emissions under the Clean Air Act; the following are the most significant ongoing Clean Air Act-related actions that affect or may affect our business.

National Ambient Air Quality Standards and Nonattainment Updates. Pursuant to sections 108 and 109 of the Clean Air Act, EPA sets National Ambient Air Quality Standards (NAAQS) for six common air pollutants: particulate matter, ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide and lead. EPA continues to review on an ongoing basis the various NAAQS and determine which are to be made more stringent. For example, after EPA lowered the primary and secondary NAAQS for ground-level ozone to 0.070 parts per million in late 2015, Georgia (like other states) submitted its proposed designations for the 2015 ozone NAAQS, recommending that eight counties be designated nonattainment. Assuming that EPA agrees with and finalizes these designations, Georgia will be obligated to revise its State Implementation Plan (SIP) to demonstrate attainment with this standard. Those measures could affect any sources located in the designated counties or, in some circumstances sources in surrounding counties if their emissions are deemed to contribute to the nonattainment status of the newly designated Atlanta-area ozone nonattainment area. EPA also took final action in 2016 on the designation of nonattainment areas for other NAAQS, like the 2010 1-hour SO_2 NAAQS and the 2012 $PM_{2.5}$ NAAQS and in both cases concluded that no nonattainment areas are to be designated in Georgia for these standards. While our coal-fired plants have installed control systems for the current suite of NAAQS, the implementation of new or revised NAAQS could lead to additional compliance requirements. The costs of any additional pollution control equipment that could be required because of new or revised NAAQS cannot be determined at this time.

Cross State Air Pollution Rule. In August 2011, EPA finalized the Cross State Air Pollution Rule (CSAPR). CSAPR imposes cap and trade programs for sulfur dioxide and nitrogen oxides emissions on fossil fuel-fired electric generating units located in twenty-eight states, including Georgia. After extensive litigation, Phase I of CSAPR began in January 2015, while Phase II of CSAPR, with its more stringent emission budgets, began in January 2017. On September 7, 2016, EPA promulgated its final CSAPR Update for the 2008 ozone NAAQS, issuing Federal Implementation Plans for 22 eastern states (not including Georgia), which generally provide updated CSAPR NO_x ozone season emissions budgets for the electric generating units within such states, beginning with the 2017 ozone season (May 1, 2017-September 30, 2017). In the rule, EPA determined that emissions from Georgia (and 13 other states) do not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states, so that further emission reductions from sources in these states to address the good neighbor provisions for the 2008 ozone NAAQS are not required. Georgia's CSAPR NO_x ozone season requirements (including its emissions budget) continue unchanged, pursuant to the state's previously-defined obligation to address the 1997 ozone NAAQS. The final CSAPR update also proposed two trading programs: (i) a NO_x ozone season Group 1 program (to which only Georgia would belong); and (ii) a Group 2 program that contains the 22 states mentioned previously. Distinct, mutually-exclusive allowances would be issued for the two trading groups, such that Group 1 allowances could not be used for compliance in a Group 2 state. Georgia could maintain its allowances, but they could not be used for out-of-state trading, unless the Group 1 allowances are first devalued by a factor of 3.5. Georgia can opt into the Group 2 trading program, by adopting a commensurate update rule emission budget. We cannot predict the ultimate outcome of this rulemaking or any ensuing litigation that may occur.

Mercury and Air Toxics Standards and State Mercury Rule. In December 2011, EPA finalized its Mercury and Air Toxics Standards (MATS) which established maximum achievable control technology limits for certain hazardous air pollutants at coal and oil-fired electric generating units. For coal units, the rule sets stringent emission limits to control various hazardous air pollutants such as mercury, non-mercury metals and acid gases and work practice standards to control organics and dioxins. Our affected generating units – which include our co-owned units at Plants Wansley and Scherer comply with MATS. In June 2015, the U.S. Supreme Court ruled that EPA must consider costs before finalizing MATS, remanding (but not vacating) the rule back to EPA for further rulemaking consistent with its opinion. On April 25, 2016, EPA finalized its Supplemental Finding that is appropriate and necessary to regulate hazardous air pollutants from coal and oil-fired electric generating units, and that MATS is reasonable. We cannot predict the outcome of this rule or any related litigation, but even if MATS is ultimately overturned, we would still need to comply with Georgia's "multi-pollutant" rule, which requires operation of existing controls at Plants Wansley and Scherer.

Startup, Shut-down or Malfunction. On June 12, 2015, EPA published a rule requiring 36 states – including Georgia – to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM), by November 22, 2016. While numerous affected states did not meet this submittal deadline, Georgia did finalize a rule and submit a corresponding SIP revision to EPA responding to the rule by the deadline. Georgia's revised rule and SIP revision do not become effective unless and until EPA accepts and approves the SIP submittal. Litigation on this rule – involving industry and many affected states – is now underway. It is possible that the current administration may act to withdraw or change the SSM rule. We cannot predict the ultimate outcome of this rulemaking or related litigation.

Air Quality Summary. While we believe that the controls installed at Plants Scherer and Wansley generally meet the requirements described above, subsequent developments, including but not limited to the results of any litigation and the implementation approaches selected by EPA and the State of Georgia, significant capital expenditures and increased operating expenses could be incurred at certain of our generating facilities, particularly Plants Scherer and Wansley.

Carbon Dioxide Emissions and Climate Change

Given the current developments in the various branches of the U.S. Government, it is unclear whether efforts to limit emissions of carbon dioxide from power plants will in the future continue. Emissions from our plants totaled 12.9 million short tons in 2016 from 10.9 million short tons in 2015, an increase due to increased operating time. In October 2015, the EPA published in the *Federal Register* its final Clean Power Plan (CPP), which was a significant part of a broader effort by the Obama Administration to reduce greenhouse gas emissions. After the U.S. Supreme Court ruled in 2007 that certain greenhouse gases, including carbon dioxide, are pollutants which EPA has the authority to regulate under the Clean Air Act, EPA determined that regulation was needed and beginning in 2009 issued a series of rules that apply the Clean Air Act Prevention of Significant Deterioration and Title V permitting programs to stationary source emissions of greenhouse gases.

In the finalized CPP, EPA establishes New Source Performance Standards (NSPS) for new and modified or reconstructed fossil-fuel-fired electric generating units. For existing fossil fuel-fired electric generating units, EPA establishes guidelines to be followed by the states when developing any final NSPS for such units. EPA seeks to reduce carbon dioxide nationwide emissions from the utility power sector by 32%, in 2030 from 2005 levels. Interim emission rates, starting in 2022 and running through 2029 are specified. For Georgia, the rule requires a 34% reduction in emission rates of covered sources from 2012 levels by 2030 (down from a 48% reduction in the proposed rule). Based on these guidelines, the resulting NSPS could impose future operational restrictions and substantial costs on our coal-fired units; although preliminary indications are that such costs will be less than had been estimated for the proposed rule.

The CPP requires the States, including Georgia, to determine how best to respond to the newly-finalized guidelines, and to develop state plans calling for these reductions in carbon dioxide emissions. Like all other states, pursuant to the rule Georgia is required to submit its plans to implement the guidelines to EPA for review and approval. On February 9, 2016, however, the U.S. Supreme Court granted numerous applications to stay the CPP guidelines, pending resolution of litigation challenging their issuance in the U.S. Court of Appeals for the District of Columbia Circuit. The stay would continue if the case proceeds for resolution to the Supreme Court, once it has been adjudicated in the District of Columbia Circuit. Our current understanding is that Georgia will not make any submittals to EPA in response to the guidelines pending resolution of the litigation. Given the changes to the various branches of the Federal Government discussed above, it is possible that such changes may affect the litigation of the CPP moving forward or the nature of the CPP itself. We cannot determine the outcome of these new EPA rules on our operations, the outcome or effect of possible litigation of Georgia's state rules to implement the emissions guidelines, the outcome of any EPA review and approval of state rules submitted in response to EPA's CPP, or the outcome of any litigation challenging EPA's CPP. We anticipate that some of the policy approaches set forth could have significant negative consequences for the economy and electric system in Georgia and in the nation, if the guidelines are implemented as finalized.

In November, 2015, the Paris Agreement was adopted at the United Nations 21st International Climate Change Conference. It establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined commitments as well as a process for increasing those commitments going forward. The Trump Administration has indicated its willingness to reconsider the Paris Agreement. Whether that will occur is unknown, and we are unable to determine the ultimate impact of the Agreement or any action that might be taken to change or nullify the Agreement on our operations or costs, including capital costs and the costs of operations.

Coal Combustion Residuals and Steam Electric Power Generating Effluent Guidelines

In October 2015, EPA published its coal combustion residuals (CCR) rule, in which it decided to regulate CCRs from electric utilities as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act. The rule contains requirements for structural integrity assessments, groundwater monitoring, location siting, composite lining, inactive units, closure and post closure, beneficial use recycling, design and operating criteria, recordkeeping, notification, and internet posting for new and existing CCR landfills, CCR surface impoundments and lateral expansions of CCR facilities. In November 2015, the EPA finalized a rule to revise the effluent limitations guidelines that apply to certain wastewater discharges from fossil fuel-fired steam electric power plants including our co-owned Plants Wansley and Scherer. Subsequently, in November 2016, and in response to EPA's CCR rulemaking, Georgia Environmental Protection Division added specific provisions for CCR wastes to its existing solid waste management rules. These rules contain the requirements in EPA's CCR rule but also add further requirements for CCR wastes in Georgia. The requirements are administered through a state permit system, with such permits issued and enforced by the State. Citizen groups retain the authority to enforce federal CCR requirements. Georgia's CCR regulations are not anticipated to have a material impact on our compliance obligations under the federal CCR rule.

In September 2015, Georgia Power announced that it is preparing a schedule to close existing ash ponds at all of its Georgia coal-fired facilities, including at our co-owned Plants Scherer and Wansley. On June 13, 2016, Georgia Power further announced that it will cease sending CCR to all of its ash ponds in Georgia within three years. It also announced that it will close the ash ponds in place using advanced engineering methods at Plants Wansley and Scherer, among other locations. The initial closure plans Georgia Power filed with the Georgia Environmental Protection Division estimated closing activities to be completed in 2026 for Plant Wansley and 2031 for Plant Scherer. Our current estimated expenditures for the settlement of related asset retirement obligations are approximately $173 million in 2016 dollars for the closure and post-closure of existing coal ash ponds. See Note 1 of Notes to Consolidated Financial Statements. In addition, preliminary estimates suggest that our capital expenditures to comply with the CCR rule and effluent limitations guidelines will be approximately $273 million for conversion to dry ash handling, landfill construction and wastewater treatment. More definitive cost estimates will be developed as the process of rule evaluation, compliance approach and design and construction implementation proceeds. The ultimate impacts associated with the federal and state CCR rules and the federal effluent limitations guidelines cannot be determined with certainty at this time.

Water Use and Wastewater Issues

In 2008, the Georgia legislature adopted a comprehensive State Water Plan that lays out statewide policies, management practices and guidance for regional water planning in Georgia. In 2011, the Georgia Environmental Protection Division adopted regional water plans that were developed pursuant to the State Water Plan. Regional plans include resource assessments, estimates of current and future water needs and management practices. Pursuant to the State Water Plan, Georgia will consider the information contained in regional water plans when making water use permitting decisions under existing state law. Regional water plans are currently under review and were updated in 2016. In addition, the state water planning process may lead to new or revised regulations for water users in the future. Because power generation is generally dependent on water usage, the regional water plans and any future regulations or other enforceable requirements developed in connection with the State Water Plan may have substantial effects on the operations of our facilities or future facilities that we construct or acquire. The impacts of future regulations or revisions to regional water plans on our facilities or future facilities cannot be determined at this time.

On October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued a stay of a final rule published jointly by EPA and the U.S. Army Corps of Engineers that revises the regulatory definition of waters of the U.S. for all Clean Water Act programs. The final rule would significantly expand the scope of federal jurisdiction under the Clean Water Act. Although the rule is not expected to have a substantial impact on our existing operations, it will likely increase permitting and regulatory requirements and costs associated with the siting and permitting of new facilities. This rule may be revised substantially by the executive branch, or it may be withdrawn. The ultimate impact of the rule will depend on the outcome of the litigation challenging its issuance, and the steps, if any that may be taken to revise or withdraw the regulation and cannot be determined at this time.

Other Environmental Matters

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

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

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 existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete shutdown of individual generating units not in compliance with these regulations. Any additional federal or state environmental restrictions imposed on our operations could result in significant additional compliance costs, including capital expenditures. Such costs could affect future unit retirement and replacement decisions and may result in significant increases in the cost of electric service. The cost impact of future legislation, regulation, judicial interpretations of existing laws or regulations, or international obligations will depend upon the specific requirements thereof and cannot be determined at this time.

Nuclear Regulation

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

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

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.

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, has successfully pursued and continues to pursue legal remedies against the Department of Energy for breach of contract. See Note 1 of Notes to Consolidated Financial Statements for information regarding the status of this litigation.

In November 2013, the U.S. District Court for the District of Columbia ordered the Department of Energy to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the Department of Energy either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. We discontinued paying the fee of approximately $9.2 million annually, based on our ownership interests, as of June 2014.

Existing on-site dry storage facilities at Plants Hatch and Vogtle can be expanded to accommodate spent fuel through the expected life of each plant.

For information concerning nuclear insurance, see Note 10 of Notes to Consolidated Financial Statements. For information regarding the Nuclear Regulatory Commission's regulation relating to decommissioning of nuclear facilities and regarding the Department of Energy's assessments pursuant to the Energy Policy Act for decontamination and decommissioning of nuclear fuel enrichment facilities, see Note 1 of Notes to Consolidated Financial Statements.

Federal Power Act

General

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

Rocky Mountain

We are subject to the hydropower licensing provisions of the Federal Power Act. Rocky Mountain is a hydroelectric project subject to licensing by the Federal Energy Regulatory Commission. The currently effective Federal Energy Regulatory Commission license to operate the Rocky Mountain project expires in 2026. See ‘‘PROPERTIES – Generating Facilities’’ for additional information.

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

Energy Policy Act of 2005

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

As a generator owner and generator operator, we are subject to certain of these mandatory reliability standards. We have established a comprehensive formal compliance program to establish, monitor, maintain and enhance our commitment to electric reliability compliance. This program includes comprehensive cyber security elements designed to protect and preserve our critical information and energy infrastructure systems. Although we intend to comply with all currently effective and enforceable reliability standards, we cannot provide assurance that we will always be in compliance. We are obligated to maintain and retain evidence of compliance with specific requirements. SERC Reliability Corporation also regularly monitors us for compliance with reliability standards. We expect that existing reliability standards will continue to be refined and that new reliability standards will be developed or adopted.

ITEM 1A. RISK FACTORS

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

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

We are contractually committed to participating in the construction of two additional nuclear units at Plant Vogtle and have committed significant capital expenditures to this endeavor. The construction of large, complex generating plants involves significant financial risk. Further, no nuclear plants have been constructed in the United States using advanced designs, such as the Westinghouse AP1000 design, and therefore estimating the total cost of construction and the related schedule is inherently uncertain. We also rely on our agents for the oversight of the construction of the additional units at Plant Vogtle and do not exercise direct control over the construction process.

Factors that have either affected construction to date or that could lead to further cost increases and schedule delays or even the inability to complete this project include:

- the financial health of Westinghouse and Toshiba and the potential insolvency or bankruptcy of one or both entities;
- the ability of another party or parties to complete the project in the event that the Contractor fails to perform under the EPC Agreement;
- loss of access to intellectual property rights necessary to construct or operate the project;
- Contractor, subcontractor and supplier performance, including compliance with the design specifications approved and quality standards set forth by the Nuclear Regulatory Commission;
- Liens on the project due to the Contractor's failure to pay third-parties;
- changes in labor costs and productivity;
- contract disputes;
- shortages and/or inconsistent quality of equipment, materials and labor;
- increases in our cost of debt financing as a result of changes in market interest rates or as a result of construction schedule delays;
- unforeseen engineering or design problems;
- permits, approvals and other regulatory matters;
- unanticipated increases in the costs of materials;
- changes in project design or scope;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- environmental and geological conditions;
- erosion of public and policymaker support;
- adverse weather conditions; and
- work stoppages.

During the course of the development and construction of Vogtle Units No. 3 and No. 4, certain of these factors have materialized and significantly impacted our project budget and the originally scheduled in-service dates. Most recently, in February 2017 the Contractor provided Georgia Power, as agent for the Co-owners, with a preliminary schedule for revised forecasted in-service dates of December 2019 for Unit No. 3 and September 2020 for Unit No. 4, delays of six months and three months from the prior forecasted in-service dates of June 2019 and June 2020, respectively. The Contractor, Georgia Power and the other Co-owners are continuing to review the schedule supporting these revised dates which must ultimately be reconciled with an integrated project schedule. Based on this continued schedule verification, at this time, we believe that the revised in-service dates of December 2019 and September 2020 do not appear to be achievable. To the extent that the Contractor is unable to meet the current revised forecasted in-service dates, such delay could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4.

Certain obligations of Westinghouse under the EPC Agreement, including, but not limited to, liquidated damages and damages related to abandoning the Vogtle project, are guaranteed by Toshiba, Westinghouse's parent company. In January 2016, as a result of credit rating downgrades of Toshiba, Westinghouse provided the Co-owners with $920 million of letters of credit pursuant to the terms of the EPC Agreement which will remain in place in accordance with the terms of the EPC Agreement. Pressure on the financial condition of Toshiba and Westinghouse could potentially affect Westinghouse and its ability to complete the construction of the new Vogtle units and affect Westinghouse and Toshiba's ability to honor any financial obligations to the Co-owners should those obligations surpass the aggregate amount of the letters of credit.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a goodwill impairment charge of over $6 billion at Westinghouse primarily attributable to the increased cost estimates to complete its nuclear projects in the United States, including Vogtle Units No. 3 and No. 4. As a result of the charge, Toshiba warned that it will likely be in a negative equity position which has created significant uncertainty regarding potential actions Toshiba may take to address this situation. At that time, Toshiba reaffirmed its commitment to its nuclear projects in the United States with implementation of management changes and increased oversight. However, since that initial announcement, Westinghouse has engaged legal and financial bankruptcy advisors, is soliciting debtor-in-possession financing packages and the likelihood that Westinghouse will file bankruptcy in the near-term has significantly increased. We are also aware that some subcontractors have asserted that the Contractor has not made payments for work performed at the Vogtle project. Georgia Power, on behalf of the Co-owners, and we are analyzing potential contingency planning scenarios and have retained legal and financial advisors in the event the Contractor fails to remedy payment any deficiencies or Westinghouse files for bankruptcy protection. A failure by Westinghouse or Toshiba to perform its obligations, including as a result of a declaration of bankruptcy by either or both of Westinghouse and Toshiba, under the EPC Agreement or the related parent guarantee, respectively, could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4.

Our current project budget for the Vogtle Units, which includes capital costs and allowance for funds used during construction, is $5.0 billion. Although many factors could increase our budget, we do not anticipate that the recently announced six and three month delays will change our current project budget. In the event that the Contractor is unable to meet the revised forecasted in-service dates, we anticipate that each month of additional delay in the near term will cost us approximately $20 million, including financing and owner's costs, net of liquidated damages. Further, a failure of Westinghouse or Toshiba to perform its obligations under the EPC Agreement or the related Toshiba parent guarantee, respectively, could have a material impact on the cost and schedule of Vogtle Units No. 3 and No. 4 and could significantly impact our project budget.

Substantial risk remains that continued challenges with the Contractor's performance, including labor productivity, fabrication, delivery, assembly and installation of plant systems, structures and components, or other issues could further impact the project schedule and cost. There have also been technical and procedural challenges to the construction and licensing of these units and additional challenges at the federal and state level may arise as construction proceeds. Further, various design and other licensing-based compliance matters, including the timely resolution of inspections, tests, analyses and acceptance criteria by the Nuclear Regulatory Commission may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners, the Contractor, or both.

The ultimate outcome of these matters cannot be determined at this time; however, these risks could continue to impact the in-service dates and cost of the additional units at Plant Vogtle which would increase 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.

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

We rely on access to external funding sources as a significant source of liquidity for capital expenditures not satisfied by cash flow generated from operations. Unlike most investor-owned utilities, electric cooperatives cannot issue equity securities and therefore rely almost entirely on debt financing.

In connection with our share of the cost to construct the additional units at Plant Vogtle, we obtained a loan from the Federal Financing Bank and a related loan guarantee from the Department of Energy to fund up to $3.1 billion of eligible project costs through 2020. As of December 31, 2016, we had advanced $1.7 billion under this loan. Continued access to the committed funds under this loan requires us to meet certain conditions related to our business and the Vogtle project and also requires certain third parties related to the Vogtle project to comply with certain laws. In addition, a failure by the Contractor to perform its obligations under the EPC Agreement could, under certain circumstances, impact our ability to make further advances under the Department of Energy guaranteed loan and give the Department of Energy discretion to require that we repay all amounts outstanding under the loan guarantee agreement over a five-year period. In the event that we are unable to draw the full amount of this loan or are required to repay amounts outstanding over a five year period, we expect that we would finance those project expenditures in the capital markets which would likely be at a higher cost.

Historically, we 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 budgetary and political pressures faced by Congress. If the amount of this funding available to us in the future is decreased or eliminated, we would seek alternative sources of debt financing in the traditional capital markets.

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

Our borrowing costs are also affected by prevailing interest rates. If interest rates have increased at the time we issue fixed rate debt or reset the interest rates on our variable rate debt, our interest costs will increase and our financial condition and future results of operations could be adversely affected.

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

- economic downturns or recessions;
- instability in domestic or foreign financial markets;
- a tightening of lending and lending standards by banks and other credit providers;
- the overall health of the energy and financial industries;
- negative events in the energy industry, such as the bankruptcy of an unrelated energy company or the occurrence of a significant natural disaster;
- lender concerns regarding potential cost overruns associated with nuclear construction;

- war or threat of war; and
- terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

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

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years. Potential future environmental laws and regulations, including those designed to address greenhouse gas emissions, including carbon dioxide, air and water quality and other matters, may result in significant increases in compliance costs or operational restrictions.

As with most electric utilities, we are subject to extensive federal, state and local environmental requirements which regulate, among other things, air pollutant emissions, wastewater discharges and the management of hazardous and solid wastes. Compliance with these requirements requires significant expenditures for the installation, maintenance and operation of pollution control equipment, monitoring systems and other equipment or facilities.

Environmental regulations have become increasingly stringent, while potential future legislation or regulations, including those relating to greenhouse gas emissions, including carbon dioxide, or renewable or clean energy may create new requirements and operational hurdles. Through 2016, we have spent approximately $1.1 billion on capital expenditures at our facilities to achieve and maintain compliance with Georgia's "multi-pollutant rule" and EPA's MATS, two air quality control regulations that have had a significant impact on our business to date. More stringent or new standards may require us to modify the design or operation of existing facilities, and could result in significant increases in the cost of electricity or decreases in the amount of energy (due to operational constraints) provided to our members. Two examples of current and potential regulations are discussed below.

In October 2015, the EPA published final rules regarding emissions of carbon dioxide from certain fossil fuel-fired electric generating units. One of the rules, referred to as the "Clean Power Plan," establishes guidelines for states to develop plans to limit emissions of carbon dioxide from certain existing fossil fuel-fired electric generating units. The guidelines and standards set forth in the Clean Power Plan could impose future operational restrictions and substantial costs on our coal-fired units. In February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending the resolution of litigation challenging the rule, in which we are participating. Additionally, the Trump administration has stated its intention to rescind the Clean Power Plan and the related guidelines. However, if the Clean Power Plan remains in place and is upheld by the Supreme Court, we anticipate that some of the policy approaches it sets forth could have significant negative consequences for the economy and electric system in Georgia and the nation.

Prior to the adoption of the Clean Power Plan, the EPA had determined that carbon dioxide and other greenhouse gases are regulated pollutants under the Clean Air Act. In the event that the Clean Power Plan is rescinded, we expect that efforts to limit the emissions of greenhouse gases, including carbon dioxide, will continue. The timing, cost and effect of any future laws or regulations attempting to reduce greenhouse gas emissions are uncertain; however, certain laws or regulations could impose substantial costs on our business and operational restrictions on certain of our generating facilities, particularly our coal-fired units.

In April 2015, the EPA published a final rule to regulate coal combustion residuals from electric utilities as solid wastes. Georgia Power has announced that ash ponds at each of its Georgia coal-fired facilities, including our co-owned facilities, will cease receiving new coal ash by early 2019 and that closure activities for the ash ponds at Plants Wansley and Scherer are initially estimated to be completed in 2026 and 2031, respectively. Currently, we and Georgia Power anticipate utilizing advanced engineering methods to close the existing ash ponds in place and continue to review the ultimate cost of this rule on our co-owned coal facilities. In September 2015, the EPA also finalized a rule to revise the effluent limitations guidelines that apply to certain wastewater discharges from nuclear and fossil fuel-fired steam electric power plants. Preliminary estimates suggest that our total cost for compliance with the coal combustion residuals rule and effluent limitations guidelines will be approximately $273 million of capital costs plus an additional

$173 million of costs associated with related asset retirement obligation liabilities.

Litigation relating to environmental issues, including claims of property damage or personal injury caused by plant emissions, wastewater discharges or solid waste disposal, including coal combustion residuals, is generally increasing throughout the U.S. Likewise, actions by private citizen groups to enforce environmental laws and regulations are becoming increasingly prevalent.

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 existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete shutdown of individual generating units not in compliance with these regulations. Any additional federal or state environmental restrictions imposed on our operations could result in significant additional compliance costs, including capital expenditures. Such costs could affect future unit retirement and replacement decisions and may result in significant increases in the cost of electric service. The cost impact of future legislation, regulation, judicial interpretations of existing laws or regulations, or international obligations will depend upon the specific requirements thereof and cannot be determined at this time. For additional information regarding certain environmental regulations to which our business is subject, see "BUSINESS – REGULATION – Environmental."

Our capital expenditures, particularly in relation to the additional units under construction at Plant Vogtle, are projected to be significant and will continue to increase our debt, which is constraining certain of our financial metrics and may also adversely affect our credit ratings.

In order to meet the energy needs of our members, we are in the midst of a multi-year capital spending plan, the centerpiece of which is our participation in the construction of Vogtle Units No. 3 and No. 4. Our project budget for the additional Vogtle units is $5.0 billion and our investment as of December 31, 2016 was $3.3 billion. As we have financed generation assets in the past, we are relying on external funding to finance this project. As of December 31, 2016, we had $8.3 billion of debt outstanding, an increase of over $4 billion since 2009, when construction of the new Vogtle units commenced. [At the completion of the Vogtle expansion, we expect that the amount of our outstanding debt will approach $10 billion]. In addition to the increase in absolute dollars, our debt had been increasing as a percentage of our total capitalization, which has constrained our equity ratio. Furthermore, our debt service payment obligations have increased, which has affected certain of our other financial metrics. Increased debt and the related impacts on our financial metrics could negatively impact our credit ratings. Any downgrade in our credit ratings could increase our borrowing costs and decrease our access to the credit and capital markets.

Beginning in 2009, in order to increase financial coverage during a period of generation expansion, our board of directors approved budgets to achieve margins for interest ratios greater than the minimum 1.10 margins for interest ratio required under our first mortgage indenture. We have achieved the board-approved margins for interest ratio each year, and for 2017 our board of directors again approved a margins for interest ratio of 1.14.

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

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 18% of our generating capacity and 40% of our energy generated during 2016. Our ownership interests in these facilities expose us to various risks, including:

- potential liabilities relating to harmful effects on the environment and human health and safety resulting from the operation of these facilities and the on-site storage, handling and disposal of radioactive materials, including spent nuclear fuel;
- uncertainties with respect to the technological and financial aspects of and the ability to maintain and anticipate adequate capital reserves for decommissioning these facilities at the end of their operational lives;
- significant capital expenditures relating to maintenance, operation, security and repair of these facilities, including repairs or modifications required by the Nuclear Regulatory Commission;

- potential liabilities arising out of nuclear incidents caused by natural disasters, terrorist attacks or otherwise, including the payment of retrospective insurance premiums, whether at our own plants or the plants of other nuclear owners; and
- uncertainties with respect to the off-site storage and disposal of spent nuclear fuel in the event that on-site storage is not sufficient.

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

Further, 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. While we have no reason to expect a serious incident at either of our nuclear plants, if an incident did occur, it could result in substantial cost to us.

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

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

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

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

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

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure. Our generation assets and information technology systems, or those of our co-owned plants, could be directly or indirectly affected by deliberate or unintentional cyber incidents. If our technology systems were to be breached or otherwise fail, we may be unable to fulfill critical business functions, including the operation of our generation assets and our ability to effectively maintain certain internal controls over financial reporting. Further, our generation assets rely on an integrated transmission system to deliver power to our members, and a disruption of this transmission system could negatively impact our ability to do so. In order to reduce the likelihood and severity of any cyber intrusion, we have comprehensive cyber security programs designed to protect and preserve the confidentiality, integrity and availability of data and systems. Despite these protections, a major cyber incident could result in significant business disruption and expenses to repair security breaches or system damage and could lead to litigation, regulatory action, including fines, and an adverse effect on our reputation.

A severe drought could reduce the availability of water and restrict or prevent the operation of certain generating facilities. Other negative events such as those discussed above could also 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.

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

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

We are exposed to the risk of changing prices for fuels, including natural gas, coal and uranium. We have taken steps to manage this exposure by entering into natural gas swap arrangements designed to manage potential fluctuations in our power rates due to changes in the price of natural gas. We have also entered into fixed or capped price contracts for some of our coal requirements. 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. Further, changes in the utilization of different generation resources may subject us to greater fuel price volatility. For example, as part of a broader effort to reduce carbon dioxide emissions, we may shift to generating more electricity at our natural gas fired facilities. Despite the recent depression in domestic natural gas prices, natural gas prices have historically been more volatile than other fuel sources and stable pricing cannot be assured. 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 natural gas, coal and uranium, from a number of different suppliers. Any disruptions in our fuel supplies, including disruptions due to weather, environmental regulations, inadequate infrastructure, labor relations or other factors affecting our fuel suppliers, could result in us having insufficient levels of fuel supplies. For example, natural gas supplies can be subject to disruption due to natural disasters and similar events, infrastructure failure or may be unavailable due to significantly increased demand caused by exceptionally cold weather. Further, the availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas. Any failure to maintain an adequate inventory of fuel supplies could require us to operate other generating plants at a higher cost or require our members to purchase higher-cost energy from other sources and, as a result, affect our members' ability to perform their contractual obligations to us.

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

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

In the context of facility construction, our counterparties' failure to perform their contractual obligations under the applicable agreements could impact the project cost and schedule and potentially project completion. As discussed above, failure of Westinghouse to perform its obligations under the EPC Agreement or failure by Toshiba to guarantee any of Westinghouse's payment obligations, will likely increase the cost of electric service we provide to our members.

We cannot predict the outcome of any current or future legal proceedings related to our business activities.

From time to time we are subject to litigation from various parties, the most significant of which are described under "LEGAL PROCEEDINGS." Our business, financial condition, and results of operations may be materially affected by adverse results of certain litigation. Unfavorable resolution of legal proceedings in which we are involved or other future legal proceedings could require significant expenditures that may increase the cost of electric service we provide to our members and, as a result, affect our members' ability to perform their contractual obligations to us.

Changes in power generation and energy storage technologies, including the broad adoption of distributed generation technologies in our members' service territories, 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. A key element of this model is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. Distributed generation or energy storage technologies currently exist or are in development, such as fuel cells, micro turbines, windmills and solar cells, that may be capable of producing or storing 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 and be broadly adopted in our members' service territories, it could adversely affect our ability to recover the fixed costs related to and the value of our generating facilities and significantly increase the cost of electric service we provide to our members and affect their ability to perform their contractual obligations to us.

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

Many of our generating facilities were constructed over 30 years ago and, even if maintained in accordance with good engineering practices, will require significant capital expenditures in order to maintain efficient and reliable operation. Potential operational issues associated with the age of the plants may lead to unscheduled outages, a generating facility being out of service for an extended period of time, or other service-related interruptions. Further, maintaining compliance with applicable efficiency, reliability and environmental standards may require significant capital expenditures or operating reductions at certain of our facilities and we may determine to reduce or cease operations at those facilities in order to avoid such capital expenditures or to meet such standards. These expenditures and service interruptions could have the effect of increasing the cost of electric service we provide to our members and, as a result, could affect our members' ability to perform their contractual obligations to us.

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.

Under current Georgia law, our members generally have the exclusive right to provide retail electric service in their respective territories, subject to limited exceptions. Parties have unsuccessfully sought and will likely continue to seek to advance legislative proposals that will directly or indirectly affect the Georgia Territorial Act in order to allow increased retail competition in our members' service territories which could affect our members' 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 resources, our members' rates could increase excessively and affect their financial performance. Also, in times of weak economic conditions, sales by our members may not be sufficient to cover costs without rate increases, and our members may not collect all amounts billed to their consumers. Although each member has financial covenants to set rates to maintain certain margin levels and our members' rates are not regulated by the Georgia Public Service Commission, pressure from their consumer members not to raise rates excessively could affect financial performance. Thus, we are exposed to the risk that one or more members could default in the performance of their obligations to us under the wholesale power contracts. Our ability to satisfy our financial obligations could be adversely affected if one or more of our members, particularly one of the larger members, defaulted on their payment obligations to us. Although the wholesale power contracts obligate non-defaulting members to pay the amount of any payment default pursuant to a pro rata step-up formula, there can be no guarantee that the non-defaulting members would be able to fulfill this obligation.

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

Our debt securities are not listed on any national securities exchange or quoted on any automated quotation system although certain series of our debt securities may be included in a fixed income index. Various dealers have made a market in certain of our debt securities and at times certain of our debt securities have an active trading market; however, other of our debt securities have no active trading market. We have remarketing agreements in place for certain of our variable rate bonds and if a particular series of new debt securities is offered through underwriters, those underwriters may attempt to make a market in the debt securities. Dealers or underwriters have no obligation to make a market in any of our debt securities and may terminate any market-making activities at any time, for any reason, without notice. Further, removal from any index may have an adverse effect on the liquidity of the trading market, if any, for our debt securities removed from that index. As a result, we cannot provide any assurance as to the liquidity of any trading market for our debt securities, the ability of holders to sell their debt securities or the price at which holders will be able to sell their debt securities.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Generating Facilities

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

Facilities	Type of Fuel	Percentage Interest	Our Share of Nameplate Capacity (MW)	Commercial Operation Date	License Expiration Date
Plant Hatch (near Baxley, Ga.)					
Unit No. 1	Nuclear	30	269.9	1975	2034
Unit No. 2	Nuclear	30	268.8	1979	2038
Plant Vogtle (near Waynesboro, Ga.)					
Unit No. 1	Nuclear	30	348.0	1987	2047
Unit No. 2	Nuclear	30	348.0	1989	2049
Plant Wansley (near Carrollton, Ga.)					
Unit No. 1	Coal	30	259.5	1976	N/A(1)
Unit No. 2	Coal	30	259.5	1978	N/A(1)
Combustion Turbine	Oil	30	14.8	1980	N/A(1)
Plant Scherer (near Forsyth, Ga.)					
Unit No. 1	Coal	60	490.8	1982	N/A(1)
Unit No. 2	Coal	60	490.8	1984	N/A(1)
Rocky Mountain (near Rome, Ga.)	Pumped Storage Hydro	74.61	632.5	1995	2026
Doyle (near Monroe, Ga.)	Gas	100	325.0	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)
Smith (near Dalton, Ga.)					
Unit No. 1	Gas	100	630.0	2002	N/A(1)
Unit No. 2	Gas	100	620.0	2002	N/A(1)

(1) Fossil-fuel 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.

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)] 2016	2015	2014	Capacity Factor[(3)] 2016	2015	2014
Plant Hatch							
Unit No. 1	262.2	90%	98%	90%	91%	99%	89%
Unit No. 2	264.3	98	89	99	98	90	100
Plant Vogtle							
Unit No. 1	344.5	100	90	86	102	91	87
Unit No. 2	344.7	94	99	90	95	100	92
Plant Wansley							
Unit No. 1	261.6	96	81	88	11	3	9
Unit No. 2	261.6	79	97	72	5	2	22
Combustion Turbine[(4)]	0	39	61	58	0	0	0
Plant Scherer							
Unit No. 1	489.2	99	82	99	55	55	78
Unit No. 2	511.4	85	97	86	48	60	67
Rocky Mountain[(5)]							
Unit No. 1	272.3	25	88	94	6	18	18
Unit No. 2	272.3	97	95	98	24	18	17
Unit No. 3	272.3	99	74	75	16	10	8
Doyle[(5)]	342.0	69	82	98	4	1	0
Talbot[(5)]	676.4	77	76	64	11	6	3
Chattahoochee	458.0	83	89	90	74	69	74
Hawk Road[(5)]	486.9	69	74	87	18	7	4
Hartwell[(5)]	301.1	57	81	74	1	1	1
Smith							
Unit No. 1	630.0	89	79	85	60	45	23
Unit No. 2	630.0	90	83	65	56	30	13
TOTAL	7,080.8						

(1) Summer Planning Reserve Capacity is the amount used for 2017 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. For 2015 and beyond, the plants operated by us and Siemens exclude periods when units are derated due to events classified under NERC guidelines as "Outside Management Control."
(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.

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. Due to low gas and market prices relative to the cost of coal purchased for Plant Wansley, it has been dispatched at lower levels in recent years.

Fuel Supply

For information regarding the electricity generated with each fuel type and its cost, see ''MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Results of Operations – *Operating Expenses.*"

Coal. Coal for Plant Wansley is purchased under term contracts and in spot market transactions. As of February 28, 2017, we had a 79-day coal supply at Plant Wansley based on continuous operation. Plant Wansley burns bituminous coal purchased primarily from coal mines in the Illinois Basin.

Coal for Scherer Units No. 1 and No. 2 is purchased under term contracts and in spot market transactions. As of February 28, 2017, our coal stockpile at Plant Scherer contained a 42-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.

We have sufficient sulfur dioxide emission allowances to support any emissions from burning this coal. For information relating to emission allowances and the impact that the Clean Air Act may have on our coal-fired facilities, see "BUSINESS – REGULATION – Environmental – *Air Quality*."

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

Natural Gas. We purchase the natural gas, including transportation and other related services, needed to operate Doyle, Talbot, Chattahoochee, Hawk Road, Hartwell and Smith. 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. 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		Plant 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	74.6	633	3,369
Georgia Power	50.1	900	45.7	1,060	53.5	926	8.4	137	25.4	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	100.0	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 Georgia's 159 counties and collectively serve approximately 309,000 electric consumers (meters). MEAG Power is Georgia'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 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. We have extended three of the leases to 2027 and the fourth lease to 2031. The leases provide for further lease renewal and also include fair market value purchase options at specified dates. See Note 6 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 1997, Georgia Power designated Southern Nuclear as the operator of Plants Hatch and Vogtle, pursuant to the Nuclear Operating Agreement between Georgia Power and Southern Nuclear, which the co-owners had previously approved. In connection with the amendments to the Plant Scherer Ownership and Operating Agreements, the co-owners of Plant Scherer entered into the Plant Scherer Managing Board Agreement which provides for a managing board to coordinate the implementation and administration of the Plant Scherer Ownership and Operating Agreements and provides for increased rights for the co-owners regarding certain decisions, but does not alter Georgia Power's role as agent with respect to Plant Scherer.

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

For Plants Hatch and Vogtle, each participant is responsible for a percentage of operating costs (as defined in the Operating Agreements) and fuel costs of each plant or unit equal to the percentage of its undivided interest which is owned or leased in such plant or unit. For Scherer Units No. 1 and No. 2 and for Plant Wansley, each party is responsible for its fuel costs and for variable operating costs in proportion to the net energy output for its ownership interest, and is responsible for a percentage of fixed operating costs equal to the percentage of its undivided interest which is owned or leased in such plant or unit. Georgia Power is required to furnish budgets for operating costs, fuel plans and scheduled maintenance plans. In the case of Scherer Units No. 1 and No. 2, the participants have limited rights to disapprove such budgets proposed by Georgia Power and to substitute alternative budgets. The Ownership Agreements and Operating Agreements provide that, should a participant fail to make any payment when due, among other things, such nonpaying participant's rights to output of capacity and energy would be suspended.

The Operating Agreements for Plant Hatch and Plant Vogtle will remain in effect with respect to each unit for so long as a Nuclear Regulatory Commission operating license exists for such unit. See "BUSINESS – 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 2018. The co-owners anticipate extending the term prior to expiration. 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 – *Plant Vogtle Units No. 3 and No. 4*"), 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. Pursuant to this ownership agreement, Georgia Power has designated Southern Nuclear as its agent for licensing, engineering, procurement, contract management, construction and pre-operation services.

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 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.

ITEM 3. LEGAL PROCEEDINGS

The ultimate outcome of pending litigation against us cannot be predicted at this time; however, we do not anticipate that the ultimate liabilities, if any, arising from such proceedings would have a material effect on our financial condition or results of operations. For information about loss contingencies that could have an effect on us, see Note 12 of Notes to Consolidated Financial Statements.

Patronage Capital Litigation

On March 13, 2014, a lawsuit was filed in the Superior Court of DeKalb County, Georgia, against us, Georgia Transmission and three of our member distribution cooperatives. Plaintiffs filed an amended complaint on July 28, 2014. The amended complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives and seeks to certify a defendant class of all but one of our 38 members. It was filed by four former consumer-members of four of our members on behalf of themselves and a proposed class of all former consumer-members of our members. Plaintiffs claim that approximately 30% of all the defendants' total allocated patronage capital belongs to former consumer-members. Plaintiffs also allege that patronage capital owed to former consumer-members includes patronage capital allocated by us to our members but not yet distributed to our members. Plaintiffs claim that the patronage capital of former consumer-members held by defendants and the proposed defendant class should be retired immediately when the consumer-members end their membership by terminating service, or alternatively, according to a revolving schedule of no longer than 13 years from the date of its allocation and seek relief to effect such retirements. Plaintiffs further seek to require the defendants to adjust rates in order to establish and maintain reasonable reserves to fund patronage capital retirements on this basis. Plaintiffs also claim that defendants and the proposed defendant class should be required to adopt policies to periodically retire the patronage capital of all consumer-members on a revolving schedule of no longer than 13 years from the date of its allocation. Our first mortgage indenture restricts our ability to distribute patronage capital. See "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture." Although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level sufficient so that we could comply with the current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiffs' demands would be significant for a period of years.

On August 20, 2014, a second patronage capital lawsuit was filed in the Superior Court of DeKalb County against us, Georgia Transmission, and two of our member distribution cooperatives. The case was filed by two current consumer-members of the two member distribution cooperatives named in the lawsuit. Similar to the above described litigation, this complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives; however, one notable difference is that the first case, described above, seeks to bring claims on behalf of former members while this second case seeks to bring claims on behalf of current members. The plaintiffs allege that the defendants have (i) retained patronage capital for an unreasonably long period of time; (ii) conspired with each other to deprive consumer-members of their patronage capital; and (iii) breached bylaw provisions allegedly requiring that patronage capital be retired when the financial condition of the cooperative will not be impaired. The plaintiffs seek unspecified damages and equitable relief, including an order declaring that the defendants be required to retire patronage capital "according to a regular, reasonable revolving plan." Similarly to the litigation described above, although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level where we could comply with current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiff's demands could be significant for a period of years. The plaintiffs seek to certify three plaintiffs' classes but do not seek to certify a defendants' class.

In May 2015, the Superior Court judge for both patronage capital lawsuits appointed a special master to oversee all pre-trial issues relating to these cases, including motions to dismiss that we and the other defendants filed in connection with each lawsuit. In September, the special master issued proposed orders to the judge to grant our and the other defendants' motions to dismiss both patronage capital lawsuits on all counts.

On May 2, 2016, the Superior Court judge adopted the special master's proposed orders and granted our and the other defendants' motions to dismiss both of these lawsuits on all counts. On May 31, 2016, plaintiffs for both of the cases appealed the Court's decision to grant the motions to dismiss to the Georgia Court of Appeals.

We intend to defend vigorously against all claims in the above-described litigation.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Not applicable.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial data. The financial data presented as of the end of and for each year in the five-year period ended December 31, 2016, has been derived from our audited financial statements. This data should be read in conjunction with ''MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS'' and the ''FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.''

(dollars in thousands)

	2016	2015	2014	2013	2012
STATEMENTS OF REVENUES AND EXPENSES DATA					
Operating revenues:					
Sales to Members	**$ 1,506,807**	$ 1,219,052	$ 1,314,869	$ 1,166,618	$ 1,204,008
Sales to non-Members	**424**	130,773	93,294	78,758	120,102
Total operating revenues	**1,507,231**	1,349,825	1,408,163	1,245,376	1,324,110
Operating expenses:					
Fuel	**513,258**	441,738	515,729	442,425	516,223
Production	**434,306**	457,264	428,801	369,730	371,909
Depreciation and amortization	**217,534**	168,920	166,247	158,375	160,849
Purchased power	**54,108**	56,925	71,799	56,084	50,022
Accretion	**32,361**	26,108	24,616	22,900	19,554
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**–**	(58,588)	(58,426)	(35,662)	(16,280)
Total operating expenses	**1,251,567**	1,092,367	1,148,766	1,013,852	1,102,277
Operating margin	**255,664**	257,458	259,397	231,524	221,833
Other income, net	**56,903**	52,030	46,371	43,433	61,487
Net interest charges	**(262,222)**	(261,147)	(259,133)	(233,477)	(244,000)
Net margin	**$ 50,345**	$ 48,341	$ 46,635	$ 41,480	$ 39,320
BALANCE SHEET DATA					
Electric plant, net:					
In service	**$ 4,671,500**	$ 4,670,310	$ 4,582,551	$ 4,434,728	$ 4,034,620
Nuclear fuel, at amortized cost	**377,653**	373,145	369,529	341,012	321,196
Construction work in progress	**3,228,214**	2,868,669	2,374,392	2,212,224	2,240,920
Total electric plant	**$ 8,277,367**	$ 7,912,124	$ 7,326,472	$ 6,987,964	$ 6,596,736
Total assets	**$10,701,113**	$10,059,783	$ 9,448,820	$ 9,048,453	$ 8,260,782
Capitalization:					
Long-term debt	**$ 8,304,523**	$ 7,575,027	$ 7,256,995	$ 6,954,293	$ 5,930,449
Obligations under capital leases	**98,531**	100,456	121,731	140,212	161,249
Obligations under Rocky Mountain transactions	**18,765**	17,561	16,434	15,379	14,392
Patronage capital and membership fees	**859,810**	809,465	761,124	714,489	673,009
Accumulated other comprehensive (gain) loss	**(370)**	58	468	(549)	903
Subtotal	**9,281,259**	8,502,567	8,156,752	7,823,824	6,780,002
Less: long-term debt and capital leases due within one year	**(316,861)**	(189,840)	(160,754)	(152,153)	(168,393)
Less: unamortized debt issuance costs	**(93,133)**	(93,651)	(97,423)	(46,759)	(53,784)
Less: unamortized bond discounts on long-term debt	**(8,128)**	(4,337)	(4,516)	(3,103)	(3,232)
Total capitalization	**$ 8,863,137**	$ 8,214,739	$ 7,894,059	$ 7,621,809	$ 6,554,593
Cash paid for property additions	**$ 613,019**	$ 495,426	$ 558,778	$ 628,216	$ 646,486
OTHER DATA					
Energy supply (megawatt-hours):					
Generated	**25,918,782**	22,408,932	21,699,553	20,648,325	24,883,009
Purchased	**49,945**	142,150	400,699	198,272	107,104
Available for sale	**25,968,727**	22,551,082	22,100,252	20,846,597	24,990,113
Member revenues per kWh sold	**5.90¢**	6.64¢	6.52¢	6.29¢	5.77¢

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

Executive Overview

General

Our principal business is reliably providing wholesale electric service to our 38 members in a safe and cost-effective manner. Consequently, our revenues and cash flow are primarily derived from sales to our members pursuant to 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 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 we collect sufficient capacity-related revenues. Our rate structure provides us with the ability to manage our revenues to assure full recovery of our costs and has enabled us consistently to meet our financial obligations since our formation in 1974.

2016 Financial Results

We remain well positioned, both financially and operationally, to fulfill our obligations to our members, bondholders and creditors. Our revenues in 2016 were more than sufficient to recover all of our costs and to satisfy all of our debt service obligations and financial covenants. Specifically, we recorded a net margin of $50.3 million in 2016, which achieved the 1.14 margins for interest ratio approved by our board of directors and exceeded the 1.10 margins for interest ratio required to meet the rate covenant under our first mortgage indenture.

Since 2009, we have targeted higher margins than necessary to meet our margins for interest ratio covenant of 1.10. We believe this is prudent due to significant capital expenditures and increased debt to fund those capital expenditures, most notably related to the construction of Vogtle Units No. 3 and No. 4. We have achieved our targeted margins in each of these years and, as a result, our patronage capital has increased significantly, from $535.8 million at December 31, 2008 to $859.8 million at December 31, 2016. For 2017, we are again targeting a margins for interest ratio of 1.14, effectively increasing our annual margins by 40% over the minimum required level. We anticipate that we will continue to target a 1.14 margins for interest ratio through the remainder of the Vogtle expansion project.

In connection with expanding our generation capacity and upgrading our generation facilities, our total assets have more than doubled to $10.7 billion at December 31, 2016 from $5.0 billion at December 31, 2008. Our total debt, including capital leases, has increased to $8.4 billion from $3.6 billion during the same period. During the remainder of the Vogtle construction period, we expect that our assets, debt and patronage capital will all continue to increase.

Additional Facilities to Serve Our Members

On January 1, 2016, we integrated the Smith and Hawk Road Energy Facilities into the pool of generation resources we utilize to meet our members' power supply needs. Smith is a 1,250-megawatt natural gas fired combined cycle facility that we acquired in 2011. Hawk Road is a 500-megawatt natural gas-fired combustion turbine facility that we acquired in 2009. Prior to 2016, we owned and operated both of these facilities; however, Smith was used primarily for third party sales and Hawk Road was dispatched to seven of our members pursuant to a power purchase agreement in place at the time of acquisition.

In 2016, these facilities produced 6.8 million megawatt hours of energy and provided significant benefits to our members. The increased generation at these facilities and the low cost of natural gas significantly contributed to the average cost per kilowatt hour of energy we delivered to our members decreasing from 6.64 cents per kilowatt hour in 2015 to 5.90 cents per kilowatt hour in 2016.

We expect these assets to provide substantial long-term value to our members in addition to providing greater diversity to our overall energy asset mix. We will continue to work with our members to evaluate other potential opportunities to expand our generation asset base to serve our members' power supply needs.

Asset Management

One of our primary focus areas continues to be ensuring that our owned and operated generation facilities perform in the most efficient and cost-effective manner possible. Our Operational Excellence program strives to achieve safety, reliability and compliance in a cost effective manner. Many of the generation facilities we operate rank in the top quartile of similar plants in one or more key performance indicators, including start reliability, peak season availability and forced outages. Achieving operational excellence results in the most reliable, efficient and lowest cost power supply for our members; therefore, effective asset management will always be one of our top priorities.

Vogtle Units No. 3 and No. 4

In addition to the efficient management of our existing resources, we and the other Co-owners of Plant Vogtle are participating in the construction and development of two additional nuclear units located at the Vogtle site. Through our agent, Georgia Power, we and the other Co-owners contracted with Westinghouse and WECTEC to construct these additional units using the Westinghouse AP1000 technology pursuant to the terms of the EPC Agreement. These units will have an aggregate generating capacity of approximately 2,200 megawatts and our 30% undivided interest will entitle us to approximately 660 megawatts of carbon-free, baseload generating capacity. Through December 31, 2016, we had invested $3.3 billion in Vogtle Units No. 3 and No. 4.

As can be the case in the construction of large, complex generation facilities, significant issues have materialized during the course of licensing and construction that have caused revisions to the original schedule and budget. In recent weeks, much of our attention has been focused on the financial viability of Westinghouse and Toshiba. On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a goodwill impairment charge of over $6 billion at Westinghouse primarily attributable to the increased cost estimates to complete its nuclear projects in the United States, including Vogtle Units No. 3 and No. 4. As a result of the charge, Toshiba warned that it will likely be in a negative equity position which has created significant uncertainty regarding potential actions Toshiba may take to address this situation. At that time, Toshiba reaffirmed its commitment to its nuclear projects in the United States with implementation of management changes and increased oversight. However, since that initial announcement, Westinghouse has engaged legal and financial bankruptcy advisors and is soliciting debtor-in-possession financing packages, significantly increasing the likelihood that Westinghouse will file bankruptcy in the near-term. We are also aware that some subcontractors have asserted that the Contractor has not made payments for work performed at the Vogtle project. Georgia Power, on behalf of the Co-owners, and we are analyzing potential contingency planning scenarios and have retained legal and financial advisors in the event the Contractor fails to remedy any payment deficiencies or Westinghouse files for bankruptcy protection. A failure by Westinghouse or Toshiba to perform its obligations, including as a result of a declaration of bankruptcy by either or both of Westinghouse and Toshiba, under the EPC Agreement or the related Toshiba parent guarantee, respectively, could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4.

In February 2017, the Contractor also provided Georgia Power, as agent for the Co-owners, with a preliminary schedule for revised forecasted in-service dates of December 2019 for Unit No. 3 and September 2020 for Unit No. 4, delays of six months and three months from the prior forecasted in-service dates of June 2019 and June 2020, respectively. The Contractor, Georgia Power and other Co-owners are continuing to review the schedule supporting these revised dates which must ultimately be reconciled with an integrated project schedule. Based on this continued schedule verification, at this time, we believe that the revised in-service dates of December 2019 and September 2020 do not appear to be achievable. Although we are discouraged by these additional delays, our current project budget of $5.0 billion would cover the delays to December 2019 and September 2020. In the event the Contractor is unable to meet the revised forecasted in-service dates, we anticipate that each month of additional delay in the near-term will cost us approximately $20 million, including financing and owner's costs, net of liquidated damages. To the extent that the Contractor is unable to meet the current revised forecasted in-service dates, such delay could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4. We believe the Contractor is responsible for any related costs for not achieving the schedule and performance guarantees in the EPC Agreement.

We have a $3.1 billion federal loan guarantee from the Department of Energy, under which we have advanced $1.7 billion as of December 31, 2016. An inability or failure by the Contractor to perform its obligations under the EPC Agreement could, under certain circumstances, impact our ability to make further advances under the loan guarantee and give the Department of Energy discretion to require that we repay all amounts outstanding under the loan guarantee agreement over a five-year period. We have had constructive discussions with the Department of Energy to keep them appraised of recent developments related to the Vogtle project and will continue to stay engaged with the Department of Energy to maintain access to this funding source. Should continued funding under the Department of Energy loan guarantee agreement become unavailable or should amounts outstanding become subject to the shorter five-year alternate amortization schedule, we would seek to finance our obligations related to Vogtle Units No. 3 and No. 4 in the capital markets which would likely be at a higher cost.

Despite the uncertainty surrounding the EPC Agreement and the financial health of Westinghouse and Toshiba, at this time we remain committed to continuing to work on the Vogtle project. We will continue to monitor and evaluate developments related to the Vogtle project and will endeavor to undertake a course of action that we believe will advance the long-term interests of our members. Georgia Power has stated that it is prepared to take appropriate actions on behalf of the Co-owners should Westinghouse or Toshiba fail to perform its obligations under the EPC Agreement and the related Toshiba parent guarantee, respectively.

For additional information regarding Vogtle Units No. 3 and No. 4 and related financing activities, see "BUSINESS—OUR POWER SUPPLY RESOURCES—Future Power Resources—*Plant Vogtle Units No. 3 and No. 4*," "MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION—Financial Condition—Financing Activities—*Department of Energy-Guaranteed Loan*" and "—*Capital Requirements—Capital Expenditures*" and Note 7a of Notes to Consolidated Financial Statements.

Environmental Regulations

A key component in effective asset management is maintaining compliance with all applicable environmental regulatory standards. In general, environmental regulations have become increasingly stringent which presents challenges to us and our members. Through 2016, we have spent approximately $1.1 billion on various projects at our coal-fired facilities in order to comply with the Georgia "multi-pollutant rule" and EPA's MATS rule. As an electric cooperative that operates on a not-for-profit basis, our compliance costs are ultimately borne by our members' electricity consumers.

In contrast to the more recent trend, the Trump administration has stated a clear intention to rescind or otherwise remove a number of environmental regulations, most notably, the EPA's Clean Power Plan. We have previously stated our belief that the Clean Power Plan is significantly flawed and could have significant negative consequences for the economy and electric systems of Georgia and nationwide. We are participating in litigation challenging the rule. In February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending resolution of this litigation.

Despite the uncertain future of the Clean Power Plan, we anticipate that efforts to reduce greenhouse gas emissions, in particular carbon dioxide, will continue. Although we cannot predict the form or timing of any such laws or regulations, we believe that we are well-situated to effectively manage such challenges and that our diverse asset base positions us well to continue to meet our members' needs. Further, our members continue to pursue potential renewable generation opportunities and invest where they deem appropriate in order to meet the demands of their member consumers and prepare for potential future limitations on greenhouse gas emissions.

Two other recent environmental regulations that are having an impact on us are the coal combustion residuals rule and effluent water regulations. In response to these rules, Georgia Power anticipates closing all of its existing ash ponds in Georgia, including the ash ponds at our co-owned coal facilities, Plants Scherer and Wansley. We expect that ash ponds at Plants Wansley and Scherer and will cease receiving new coal ash in 2019 and that the closure activities will be complete by 2026 and 2031, respectively. Preliminary analysis of those rules indicates that our cost to comply will be approximately $445 million, which includes both capital costs and asset retirement obligation liabilities.

Liquidity Position

One of the most positive attributes contributing to our solid financial standing is our strong liquidity position. This liquidity is comprised of a diversified, cost-effective mix of cash (including short-term investments), committed lines of credit and commercial paper. Our primary source of liquidity is a $1.2 billion unsecured credit facility that extends through March 2020 and which supports our $1.0 billion commercial paper program. We have another $400 million available through additional secured and unsecured credit facilities.

We also have a $3.1 billion Department of Energy-guaranteed loan in place to finance a significant portion of the additional Vogtle units. As of December 31, 2016, we had advanced $1.7 billion under this loan. Additionally at December 31, 2016, we had $506 million under approved loans remaining to be advanced from the Rural Utilities Service to finance general and environmental improvements at our existing plants.

With our current sources of committed short-term and long-term funding, we anticipate that we will have sufficient liquidity to continue progress on Vogtle Units No. 3 and No. 4.

Outlook for 2017

We remain focused on providing reliable, safe, and cost-effective energy to our members and the 4.1 million people they serve and believe we are well positioned to do so. As discussed above, there are certain risks and challenges that we must continue to address; however, as we manage our risks, we intend to keep doing what we have done so successfully for the last 43 years, including, among other things:

- maintaining a balanced diversity of generating resources, including nuclear, natural gas, coal and hydro and continuing the efficient and cost-effective operation of these resources;
- maintaining strong liquidity to fulfill current obligations and to finance future capital expenditures; and
- working with our members, as opportunities arise, to evaluate new resources to be acquired or developed by us to help meet our members' power supply requirements.

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 Policies

We have determined that the following accounting policies are 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 these critical accounting policies and the related estimates and assumptions with the audit committee of our board of directors.

Regulatory Accounting. We are subject to the provisions of the Financial Accounting Standards Board (FASB) authoritative guidance issued regarding regulated operations. The guidance permits us to record regulatory assets and regulatory liabilities to reflect future cost recoveries or refunds, respectively, that we have a right to pass through to our members. At December 31, 2016, our regulatory assets and liabilities totaled $545.4 million and $197.7 million, respectively. While we do not currently foresee any events such as competition or other factors that would make it not probable that we will recover these costs from our members as future revenues through rates under our wholesale power contracts, if such an event were to occur, we could no longer apply the provisions of accounting for regulated operations, which would require us to eliminate all regulatory assets and liabilities that had been recognized as a charge to our statement of revenues and expenses and begin recognizing assets and liabilities in a manner similar to other businesses in general. In addition, we would be required to determine any impairment to other assets, including plants, and write-down those assets, if impaired, to their fair values.

Asset Retirement Obligations. Accounting for asset retirement and environmental obligations requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Estimating the amount and timing of future expenditures includes, among other things, making projections of when assets will be retired and ultimately decommissioned, the amount of decommissioning costs, and how costs will escalate with inflation.

A significant portion of our asset retirement obligations relates to our share of the future cost to decommission our operating nuclear units. At December 31, 2016, our nuclear decommissioning asset retirement obligation totaled $517.6 million, which represented approximately 74% of our total asset retirement obligations. Our remaining asset retirement obligations relate to non-nuclear retirement obligations such as those related to our share of coal facilities.

Given its significance, we consider our nuclear decommissioning liabilities critical estimates. Approximately every three years, new decommissioning studies for Plants Hatch and Vogtle are performed. These studies provide us with periodic site-specific ''base year'' cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for the plants. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption. Our current estimates are based upon studies that were performed in 2015. For ratemaking purposes, we record decommissioning costs over the expected service life of each unit. The impact on measurements of asset retirement obligations using different assumptions in the future may be significant.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued ''Revenue from Contracts with Customers'' (Topic 606). The new revenue standard requires that an entity recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The standard was effective for the annual reporting period beginning after December 15, 2016 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes additional footnote disclosures). Early adoption was not permitted.

In August 2015, the FASB issued an update to Topic 606 deferring the effective date by one year. The standard is effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. The standard also permits early adoption of the standard, but not before the original effective date of December 15, 2016.

While we expect that the majority of our revenues will be included in the scope of Topic 606, we have not fully completed our evaluation of the new revenue standard. Our evaluation process includes, but is not limited to, identifying contracts within the scope of Topic 606, reviewing and documenting our accounting for these contracts and assessing the applicability of the variable consideration guidance. A large majority of our revenues is derived from substantially identical wholesale power contracts that we have with each of our 38 members. We expect the pattern of revenue recognition pursuant to our wholesale power contracts will remain unchanged on an annual basis under the new revenue standard. However, we continue to evaluate the effects, if any, of Topic 606 on our interim period revenues as it relates to budget adjustments, which may be made during the year that affect our annual revenue requirement. We also continue to evaluate other revenue streams and the related contracts, as well as monitor issues specific to the power and utilities industry. As the ultimate impact of the new revenue standard has not yet been determined, we have not elected our transition method.

In July 2015, the FASB issued ''Inventory (Topic 330): Simplifying the Measurement of Inventory.'' Under the new inventory standard, inventories are required to be measured at the lower of cost and net realizable value, the latter representing the estimated selling price in the ordinary course of business, reduced by costs of completion, disposal, and transportation. Under current guidance, inventories are required to be measured at the lower of cost or market, but depending upon specific circumstances, market could be replacement cost, net realizable value, or net realizable value reduced by a normal profit margin. The amendments do not apply to inventory measured using the last-in, first-out or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first out or average cost, the method used to measure all of our inventories. The new standard is effective for us prospectively for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted as of the beginning of an interim or annual reporting period. As permitted, on April 1, 2016, we early adopted these amendments and applied their provisions prospectively. The adoption of this amendment did not have a material impact on our consolidated financial statements.

In November 2015, the FASB issued "Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes." The amendments in this standard simplifies the presentation of deferred income taxes by eliminating the separate classification of deferred income tax assets and liabilities into current and noncurrent amounts in the statement of financial position. The amendments in the update require that all deferred tax assets and liabilities be classified as noncurrent in the consolidated balance sheets. The new standard is effective for us either prospectively or retrospectively for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted as of the beginning of an interim or annual reporting period. As permitted, on October 1, 2016, we early adopted these amendments and applied their provisions retrospectively. There was no impact to our consolidated financial statements as a result of the adoption of this standard.

In January 2016, the FASB issued "Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities." The amendments in this update address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. The new standard is effective for us for annual reporting periods beginning after December 15, 2017, and interim periods therein. Certain provisions within this update can be adopted early. Certain provisions within this update should be applied by means of a cumulative effect adjustment to the balance sheets of the fiscal year of adoption and certain provisions should be applied prospectively. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In February 2016, the FASB issued "Leases (Topic 842)." The new leases standard requires a dual approach for lessee accounting under which a lessee would account for leases as finance leases or operating leases. Both finance leases and operating leases will result in the lessee recognizing a right-of-use (ROU) asset and a corresponding lease liability. For finance leases the lessee would recognize interest expense and amortization of the ROU asset and for operating leases the lessee would recognize a straight-line total lease expense. The new lease standard does not substantially change lessor accounting. The new leases standard is effective for us on a modified retrospectively approach for annual reporting periods beginning after December 15, 2018, and interim periods therein. Early adoption is permitted. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In June 2016, the FASB issued "Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." The amendments in this update replace the current incurred loss impairment methodology with a methodology that reflects expected credit losses. The new standard is effective for us prospectively for annual reporting periods beginning after December 15, 2019, and interim periods therein. The amendments in this update can be adopted earlier as of the fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In August 2016, the FASB issued "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." The amendments in this standard provide specific guidance on eight cash flow classification issues relating to how certain cash receipts and cash payments are presented and classified in the statement of cash flows, thereby reducing the current and potential future diversity in practice. The new standard is effective for us for annual reporting periods beginning after December 15, 2017, and interim periods therein. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. The amendments should be applied using a retrospective transition method to each period presented. If it is impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of the earliest date practicable. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In November 2016, the FASB issued "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)." The amendments in this standard require the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are to be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period amounts shown on the statement of cash flows. The new standard is effective for us on a retrospectively basis for annual reporting periods beginning after December 15, 2017, and interim periods therein. Early adoption is permitted, including adoption in an interim period. Our restricted cash balances are nominal and accordingly we do not expect the adoption of this standard to have a material impact on our consolidated financial statements.

Summary of Cooperative Operations

Sources of Revenues

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. We supply capacity and energy to our members for a portion of their energy requirements which is our primary source of revenues. We may also sell capacity and energy to non-members. Capacity revenues are the revenues we receive for electric service whether or not our generation and purchased power resources are dispatched to produce electricity. Energy revenues are the revenues we receive by selling electricity which we generate or purchase.

We have assigned fixed percentage capacity cost responsibilities to our members for all of our generation and purchased power resources. Each member has contractually agreed to pay us for the electric capacity assigned to it based on its individual fixed percentage capacity cost responsibility.

Each member is also contractually obligated to pay us for electric energy we provide to it based on individual usage. We do not provide our members with all of their energy requirements; however, our energy sales to our members fluctuate from period to period based on several factors, including fuel costs, 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.

Formulary Rate

The rates we charge our members are designed to cover all of our costs plus a margin. This cost-plus rate structure is set forth as a formula in the rate schedule to the wholesale power contracts between us and each of our members. These contracts require us to design capacity and energy rates that generate revenues sufficient to recover all costs, including payments of principal and interest on our indebtedness, to establish and maintain reasonable margins and to meet the financial coverage requirements under the first mortgage indenture.

The formulary rate provides for the pass through of our fixed costs to members as capacity charges and our variable costs to members as energy charges. Fixed costs are assigned to members according to their individual fixed percentage capacity cost responsibility for each resource in which they participate, and variable costs are passed through to our members as energy charges based on the amount of energy supplied to each member.

Capacity charges are based on an annual budget of fixed costs plus a targeted margin and are billed to members in equal monthly installments over the course of the year. Fixed costs include items such as depreciation, interest, fixed operations and maintenance expenses, administrative and general expenses. We monitor fixed cost budget variances to projected actual costs 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 targeted margin. Budget adjustments are typically made twice a year; once during the first quarter and again at year end. In contrast to the way we bill our members for capacity charges, which are billed based on a budget and trued up to actuals by the end of the year, energy charges are billed on a more real-time basis. Estimated energy charges are billed to members based on the amount of energy supplied to each member during the month, and are adjusted when actual costs are available, generally the following month. Energy charges, or variable costs, include fuel, purchased energy and variable operations and maintenance expenses. Each generating resource has a different variable cost profile, and members are billed based on the energy cost profile of the resources from which their energy is supplied.

Margins

Revenues in excess of current period costs in any year are designated as net margin in our statements of revenues and expenses and we have generated a positive net margin every year since our formation in 1974. Under our first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates that are reasonably expected, together with our other revenues, to yield a margins for interest ratio for each fiscal year equal to at least 1.10. See "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture" for a discussion of how we calculate our margins for interest ratio.

In the event we were to fall short of the minimum 1.10 margins for interest ratio at year end, the formulary rate is designed to recover the shortfall from our members in the following year without any additional action by our board of directors.

Prior to 2009, we budgeted and achieved annual margins for interest ratios of 1.10, the minimum required by the first mortgage indenture. To enhance margin coverage during a period of increased capital requirements, our board of directors has approved budgets with margins for interest ratios that exceeded 1.10. Since 2010, we have achieved our board approved margins for interest ratio of 1.14, and our board has approved a margins for interest ratio of 1.14 for 2017. As our capital requirements continue to evolve, our board will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

Patronage Capital

Retained net margins are designated on our balance sheets as patronage capital. As a cooperative, patronage capital constitutes our principal equity. As of December 31, 2016, we had $859.8 million in patronage capital and membership fees. Our equity ratio, calculated pursuant to our first mortgage indenture as patronage capital and membership fees divided by total capitalization and long-term debt due within one year, was 9.3% and 9.5% at December 31, 2016 and December 31, 2015, respectively.

Patronage capital is allocated to each of our members on the basis of their fixed percentage capacity responsibilities in our generation resources. Any distribution of patronage capital is subject to the discretion of our board of directors and limitations under our first mortgage indenture. See "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture" for a discussion regarding limitations on distributions under our first mortgage indenture.

Rate Regulation

Under our loan agreements with each of the Rural Utilities Service and Department of Energy, changes to our rates resulting from adjustments in our annual budget are generally not subject to their approval. We must provide the Rural Utilities Service and Department of Energy with a notice of and opportunity to object to most changes to the formulary rate under the wholesale power contracts. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders – *Rural Utilities Service*." Currently, our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

Tax Status

While we are a not-for-profit membership corporation formed under the laws of Georgia, we are subject to federal and state income taxation. As a taxable cooperative, we are allowed to deduct patronage dividends that we allocate to our members for purposes of calculating our taxable income. We annually allocate income and deductions between patronage and non-patronage activities and substantially all of our income is from patronage-sourced activities, resulting in no current period income tax expense or current income tax liability. For further discussion of our taxable status, see Note 5 of Notes to Consolidated Financial Statements.

Results of Operations

Factors Affecting Results

Certain of our recent financial and operational results were affected both by the way in which we dispatch our power plants as well as by significant events or trends described below.

We have a diverse mix of generation and fuel types among our power plants, allowing us to serve the power needs of our members in a reliable, efficient and low-cost manner. The types of generation assets we own include several natural gas-fired simple cycle combustion turbines, two combined cycle natural gas-fired plants, a plant that burns bituminous coal, a plant that burns sub-bituminous coal, two nuclear plants and a pumped storage hydroelectric plant.

Until the beginning of 2016, two of our facilities were not generally used to serve member load. Smith, a 1,250-megawatt combined cycle natural gas-fired plant we acquired in 2011, was used prior to 2016 extensively for off-system sales. Additionally, one of our simple cycle natural gas-fired plants, Hawk Road, was available only to serve seven of our members or for off-system sales until the beginning of 2016. These two facilities were acquired on favorable terms with the knowledge that our members generally would not require the energy generation until 2016. During this time, the effect on net margin of the revenues and expenses at Smith and Hawk Road were deferred, and when we began dispatching these units to serve member load in 2016, we began recovering the net effect of these deferrals from our members.

Starting in 2016, we began dispatching Smith exclusively to serve member load, and therefore member kilowatt-hour sales increased significantly, non-member sales substantially ended, and the average cost of energy sold to members decreased significantly. When we began dispatching Smith to serve member load, we experienced an increase in overall generation from Smith since member energy requirements have been a more consistent source of demand than general market demand. Additionally, in 2016, we began charging members to recover both the current fixed costs and the previously deferred net costs of Smith, which along with the increased generation from Smith resulted in significantly increased sales revenues from members. This included higher energy charges due to a greater number of kilowatt-hours of energy that we generated and sold to members from Smith as well as increased member capacity revenues from Smith to recover fixed operating costs, depreciation and interest on the initial acquisition costs, as well as the amortization of previously deferred fixed costs of Smith. Although these capacity revenues increased, the increase in kilowatt-hours of energy sold to members was greater than the increase in total cost of the additional member sales from Smith, so the average cost of energy we sold to our members decreased significantly in 2016 compared with both 2015 and 2014.

Decisions to dispatch our power plants are economically driven by supply and demand considerations. The primary supply considerations include fuel prices and other marginal operating costs of the plant, which factor into a dispatch cost we calculate for each resource, and plant availability, which is driven by factors such as outages for maintenance or refueling. We prioritize the order in which we dispatch our plants such that we dispatch our available plants with the lowest dispatch cost first, and those with the highest dispatch cost last, when demand is highest. The primary demand consideration that affects how we dispatch our plants is the amount of energy our members require from us. Our members' energy demand is a function of weather, economic activity, residential use patterns and the relative cost and availability of our members' third party supply arrangements, which account for a significant portion of the energy they purchase.

Since we pass through all of our costs to members, including fuel cost, which is one of our most significant operating costs, the cost of our energy sales to our members is significantly affected by fuel prices, and the price of natural gas is the most significant variable in our cost of fuel. Natural gas prices have fluctuated significantly in the last ten years and were near recent historic lows during much of 2016. As a result, our average cost of natural gas per kilowatt-hour of gas-fired generation was lower in 2016 than in both 2015 and 2014 although in 2016 our total cost of natural gas, as well as our total fuel cost, were higher than in those years due to increased gas-fired generation, particularly at Smith.

In 2015, the price of natural gas was lower than in 2014 and the lower natural gas prices also led to increased generation at Smith which drove the total number of kilowatt-hours we generated in 2015 higher compared to 2014. Since Smith generation was sold to non-members in 2015, as well as in 2014, this did not affect member sales, and, in fact, member kilowatt-hour sales declined slightly in 2015 compared to 2014. As a result of lower natural gas prices, the amount of coal-fired generation we sold to members has decreased each year from 2014 through 2016. The reduction in coal-fired generation between 2015 and 2016 was principally driven by a reduction in generation at Plant Scherer offset by a slight increase at Plant Wansley.

Each of our two coal-fired plants is capable of burning different types of coal, and therefore the cost of coal varies between those plants depending on market conditions. We burn bituminous coal from the Appalachian or Illinois Basin at Plant Wansley which is currently more expensive than the sub-bituminous coal we burn from the Powder River Basin at Plant Scherer.

Due to the higher relative cost of its fuel supply, Plant Wansley's generation has been significantly reduced since 2013, but experienced an increase in 2016 compared with 2015. The increased generation at Plant Wansley in 2016 was a result of lower dispatch costs after we made a $15 million adjustment to the coal inventory at Plant Wansley. The adjustment, which was recorded as a regulatory asset, lowered the cost of this inventory to its replacement cost. As such, the excess cost of this coal inventory is no longer factored into the plant's dispatch cost. Instead, we are now recovering the $15 million regulatory asset from our members over a five year period as a fixed charge. This resulted in slightly increased scheduling of Plant Wansley in 2016 compared to 2015.

In 2014, Plant Wansley was dispatched to conduct extensive testing of environmental equipment placed into service in 2014 and was also dispatched more extensively during a period of extremely cold weather in 2014 when gas supplies were more difficult to obtain and our energy demand was very high. Notwithstanding the recently reduced usage, Plant Wansley remains a valuable asset for us and our members and we benefit from the diversity it adds to our generation mix and from the reserve capacity it adds to our system.

Our nuclear units require refueling on an 18 to 24-month cycle and these refueling outages, which typically last several weeks, resulted in fluctuations in nuclear plant availability and generation in each of the last three years. These shutdowns and outages significantly reduced generation at the affected plants, reduced kilowatt-hour sales to and energy revenues from our members during the period that the plants were not generating power.

Our energy sales to our members also fluctuate from period to period based on weather. Summer in 2016 was relatively hot and as a result, member demand and energy requirements, and therefore, energy sales to our members were higher in 2016 compared with 2015 and 2014. The higher 2016 energy sales also contributed to higher fuel costs and, consequently, higher operating expenses in 2016.

We have also continued to make significant capital expenditures over the past three years, particularly for the new units at Plant Vogtle, which we have primarily financed with debt. These financings have increased our overall debt which has increased our interest expense and our allowance for debt funds used during construction. Additionally, since our margin is calculated as a percentage of our secured interest expense, our net margin has also increased. As discussed under "– Financial Condition – *Capital Resources – Capital Expenditures*," we expect significant capital expenditures to continue through the completion of the additional units at Plant Vogtle.

Net Margin

Our net margin for the years ended December 31, 2016, 2015 and 2014 was $50.3 million, $48.3 million and $46.6 million, respectively. These amounts produced a margins for interest ratio of 1.14 in each of 2016, 2015 and 2014. For additional information on our margin requirement, see "– Summary of Cooperative Operations – *Rate Regulation.*"

Operating Revenues

Sales to Members. We generate revenues principally from the sale of electric capacity and energy to our members. Capacity revenues are the revenues we receive for electric service whether or not our generation and purchased power resources are dispatched to produce electricity, and are designed to recover the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges, plus a targeted margin. Energy revenues are earned by selling electricity to our members, which involves generating or purchasing electricity for our members. Energy revenues recover the variable costs of our business, including fuel, purchased energy and variable operation and maintenance expense.

The components of member revenues were as follows:

		(in thousands)		2016 vs. 2015	2015 vs. 2014
	2016	2015	2014	% Change	% Change
Capacity revenues	**$ 896,412**	$ 772,069	$ 752,686	16.1%	2.6%
Energy revenues	**610,395**	446,983	562,183	36.6%	(20.5)%
Total	**$ 1,506,807**	$ 1,219,052	$ 1,314,869	23.6%	(7.3)%
kWh Sales	**25,522,852**	18,371,558	20,154,108	38.9%	(8.8)%
Cents/kWh	**5.90**	6.64	6.52	(11.1)%	1.8%

Beginning in 2016, we began dispatching Smith and Hawk Road to serve member load. As a result, capacity revenues increased 16.1% in 2016 compared to 2015 primarily as a result of the recovery of fixed costs at these plants. Prior to 2016, our members did not require the energy generation from Smith and Hawk Road and the effects of the revenues and expenses from these resources on net margin were deferred. Capacity revenues increased slightly in 2015 compared to 2014.

Energy revenues also increased in 2016 compared to 2015 primarily due to an increase in generation for member sales as a result of Smith and Hawk Road being available to our members. The average energy revenue per kilowatt-hour from sales to members decreased 11.1% in 2016 compared to 2015. Our members' ability to schedule these additional natural gas-fired facilities, which currently provide an economical source of energy due to low natural gas prices, significantly increased our kilowatt-hour sales to our members and allowed us to provide a larger percentage of our member's load requirements in 2016. Slightly offsetting the increase was a decrease in revenues related to purchased power energy.

The decrease in energy revenues from members in 2015 compared to 2014 was primarily due to a decrease in generation for member sales, a decrease in fuel costs and, to a lesser extent, a decrease in purchased power energy. Kilowatt-hour sales to members were somewhat lower in 2015 as members procured a larger portion of their load requirements from other sources, primarily as a result of lower natural gas prices. Lower member demand was also partially a result of milder weather in 2015 as compared to 2014. Average energy revenue per kilowatt-hour from sales to members decreased 12.8% in 2015 compared to 2014 as a result of lower fuel costs. For a discussion of fuel costs and purchased power costs, see "– *Operating Expenses*."

Sales to Non-members. Prior to 2016, sales to non-members consisted primarily of capacity and energy sales at Smith. Non-member sales decreased 99.7% in 2016 compared to 2015 as Smith became available for scheduling by our members and opportunities for sales to non-members were greatly reduced. Non-member sales increased 40.2% in 2015 compared to 2014 as a result of the relatively lower average cost of power generated at Smith due to lower natural gas prices.

Operating Expenses

Our operating expenses increased 14.6% in 2016 compared to 2015 and decreased 4.9% in 2015 compared to 2014. The increase in 2016 compared to 2015 was primarily due to an increase in fuel costs, depreciation and amortization and the effect of Smith and Hawk Road deferred net margins. The decrease in 2015 compared to 2014 was primarily due to lower fuel and purchased power costs.

The following table summarizes our kilowatt-hour generation and fuel costs by generating source.

	Cost					Generation					Cents per kWh				
	(dollars in thousands)					(kWh in thousands)									
Fuel Source	**2016**	2015	2014	2016 vs. 2015 % Change	2015 vs. 2014 % Change	**2016**	2015	2014	2016 vs. 2015 % Change	2015 vs. 2014 % Change	**2016**	2015	2014	2016 vs. 2015 % Change	2015 vs. 2014 % Change
Coal	**$ 141,773**	$ 142,113	$ 213,655	(0.2%)	(33.5%)	**4,800,836**	5,013,312	6,943,974	(4.2%)	(27.8%)	**2.95**	2.83	3.08	4.2%	(7.9%)
Nuclear	**83,751**	78,762	85,166	6.3%	(7.5%)	**10,344,201**	10,151,539	9,771,058	1.9%	3.9%	**0.81**	0.78	0.87	3.8%	(11.0%)
Natural Gas:															
Combined Cycle	**221,851**	182,818	186,950	21.4%	(2.2%)	**8,916,272**	6,890,245	4,961,570	29.4%	38.9%	**2.49**	2.65	3.77	(6.0%)	(29.6%)
Combustion Turbine	**65,883**	38,045	29,958	73.2%	27.0%	**1,743,795**	789,041	445,787	121.0%	77.0%	**3.78**	4.82	6.72	(21.6%)	(28.3%)
	$ 513,258	$ 441,738	$ 515,729	16.2%	(14.3%)	**25,805,104**	22,844,137	22,122,389	13.0%	3.3%	**1.99**	1.93	2.33	3.1%	(17.1%)

Total fuel costs increased in 2016 compared to 2015 primarily as a result of a 39% increase in generation at our natural gas-fired plants. The effect of increased generation on fuel cost was partially moderated by lower average natural gas prices during the first half of 2016. A combination of the lower natural gas prices and the ability of our members to schedule Smith and Hawk Road in 2016 were the primary contributors to the increase in total generation. Also contributing to increased fuel costs in 2016 was a $7.1 million reduction in fuel expense in 2015 associated with the recovery of spent nuclear fuel storage costs from the U.S. Department of Energy. The exclusion of the credit would have resulted in (i) 2015 nuclear fuel costs of $85.8 million, a 2.4% decrease in 2016 compared to 2015 and (ii) a 4.2% decrease in the average cost per kilowatt-hour generation in 2016 compared to 2015. The decrease in total fuel costs for 2015 compared to 2014 was primarily due to lower average natural gas prices and a shift in the generation mix from the coal-fired units to the relatively more economical natural gas-fired combined cycle units. Generation at our coal-fired plants during 2015 compared to 2014 decreased 28%, while our natural gas-fired plants' generation increased 42%. The decrease in generation, and therefore fuel costs, at our coal-fired units was attributable in part to (i) extensive testing of environmental controls at Plant Wansley in 2014, (ii) more moderate winter weather in 2015 and (iii) our members procuring a larger portion of their load requirements in 2015 from other sources, primarily as a result of lower natural gas prices. While total generation increased during 2015, the increase was primarily due to generation at Smith for non-member sales.

Changes in total fuel costs are also impacted by the amount of realized gains and losses incurred for natural gas financial hedging contracts utilized for managing our exposure to fluctuations in market prices of natural gas. During 2016 we realized a net loss of $17.3 million. For 2015 we realized a net loss of $19.9 million and for 2014, we realized net gain of $0.8 million.

Depreciation and amortization expense increased 28.8% in 2016 compared to 2015 primarily due to the adoption of new depreciation rates for our co-owned nuclear and coal-fired plants. The new depreciation rates are higher than the previous rates largely as a result of capital additions from environmental controls and costs associated with interim retirements. Also contributing to the 2016 increase was the completion in 2015 of the amortization of the deferred asset related to the effect of Smith on net margins, and an increase in depreciation associated with certain asset retirement obligations. Depreciation expense increased slightly from 2015 compared to 2014.

Production costs decreased 5.0% in 2016 compared to 2015 and increased 6.4% in 2015 compared to 2014. The respective decrease and increase in 2016 and 2015 was primarily due to planned major maintenance costs at Smith and Hawk Road that were incurred in 2015; similar costs were not incurred in 2016.

The decrease in purchased power in 2016 compared to 2015 and 2015 compared to 2014 was primarily a result of a decrease in kilowatt-hours acquired under our energy replacement program, which replaces power from our owned generation facilities with power purchased on the spot market at a lower price. From 2015 to 2014, kilowatt-hours purchased decreased 65%.

The deferral of the Hawk Road and Smith effect on net margin ceased as of December 31, 2015. The deferred amounts are being amortized, which began in 2016, over the remaining lives of the plants. The amortization is recorded as a component of depreciation and amortization expense.

Other Income

Investment income increased 27.8% in 2016 compared to 2015. The increase is primarily related to an increase in investment income associated with nuclear decommissioning. We use the accounting provision for regulated operations for our nuclear decommissioning transactions, and record a regulatory asset or liability to reflect the difference in the timing of recognition of decommissioning expenses for financial statement purposes compared to the expense recovered for ratemaking purposes. As a result of this treatment, nuclear decommissioning related investment income increased $9.1 million, which equaled the increase in nuclear decommissioning expense for the period. The increase in nuclear decommissioning expense was driven by an increase in cash flow estimates made pursuant to nuclear decommissioning studies completed in 2015. Investment income increased 9.9% in 2015 compared to 2014 and was primarily due to increased earnings from the Rural Utilities Service Cushion of Credit account due to a higher average balance in 2015. The higher balance in the account was largely due to increased participation by our members in the power bill prepayment program. See Note 1 of Notes to Consolidated Financial Statements for further discussion of the nuclear decommissioning investments.

Interest Charges

The increases in interest on long-term debt and capital leases in 2016 and 2015 as compared to the respective prior years were primarily due to increased debt issued to finance the construction of Vogtle Units No. 3 and No. 4. We expect interest on long-term debt to continue to increase in future years as we issue additional debt to finance the construction of Vogtle Units No. 3 and No. 4.

Financial Condition

Overview

Consistent with our budgeted margin for 2016, we achieved a 1.14 margins for interest ratio which produced a net margin of $50.3 million. This net margin increased our total patronage capital (our equity) and membership fees to $859.8 million at December 31, 2016. Our 2017 budget again targets a 1.14 margins for interest ratio.

Our equity to total capitalization ratio, as defined in our first mortgage indenture, decreased slightly from 9.5% at December 31, 2015 to 9.3% at December 31, 2016. The main factors causing the slight decrease was a new money issuance of $250 million of first mortgage bonds in April 2016 and a larger amount of advances under our Federal Financing Bank loan guaranteed by the Department of Energy covering the Vogtle expansion in 2016 as compared to 2015. We anticipate that our equity ratio will remain around its current level during the remainder of the Vogtle construction period; however, the absolute level of patronage capital will continue to increase.

We had a strong liquidity position at December 31, 2016, with $1.6 billion of unrestricted available liquidity, including $366.3 million of cash and cash equivalents. We issued commercial paper throughout the year to provide interim financing for the Plant Vogtle construction and for other purposes at a very low cost. The average cost of funds on the $102.2 million of commercial paper outstanding at December 31, 2016 was 0.93%.

Our total assets increased to $10.7 billion at December 31, 2016 from $10.1 billion at December 31, 2015. The majority of this increase relates to an increase in total electric plant in connection with constructing the two additional nuclear units at Plant Vogtle.

Property additions during 2016 totaled $613.0 million. These additions include costs related to the construction of the new Vogtle units, environmental control facilities being installed at Plants Scherer and Wansley, normal additions and replacements to existing generation facilities and purchases of nuclear fuel.

In 2016, we advanced $497.8 million, including capitalized interest, under our Department of Energy-guaranteed loan for the new Vogtle units and $94.5 million under various Rural Utilities Service-guaranteed loans for general and environmental improvements. See "– *Financing Activities*" for a discussion of the long-term financing of the new Vogtle units.

There was a net increase in long-term debt and capital leases of $727.6 million at December 31, 2016 compared to December 31, 2015. The weighted average interest rate on the $8.3 billion of long-term debt outstanding at December 31, 2016 was 4.34%.

Sources of Capital and Liquidity

Sources of Capital. We fund our capital requirements through a combination of funds generated from operations and short-term and long-term borrowings. In 2014, we obtained a loan from the Federal Financing Bank that is guaranteed by the Department of Energy that we expect to fund up to $3.1 billion of the cost to construct our 30% undivided interest in the two new nuclear units at Plant Vogtle. Our continued access to funds under the Department of Energy-guaranteed loan is subject to our ability to meet certain conditions related to our business and the Vogtle project and also requires certain third parties related to the Vogtle project to comply with certain laws. See Note 7a in Notes to Consolidated Financial Statements for additional information regarding this loan.

Historically, we have also obtained a substantial portion of our long-term financing from Rural Utilities Service-guaranteed loans funded by the Federal Financing Bank. However, Rural Utilities Service funding levels for projects we may choose to undertake are uncertain and may be limited at any point in the future due to budgetary and political pressures faced by Congress. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service loans that may be available to us in the future. We have also issued a substantial amount of taxable and tax-exempt debt in the capital markets, and if the Rural Utilities Service loan program were to be curtailed or eliminated in the future, we believe we are well positioned to continue to access capital market financings.

See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders."

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, 2016, we had $1.6 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of $366.3 million of cash and cash equivalents and $1.3 billion of unused and available committed credit arrangements.

Net cash provided by operating activities was $325.4 million in 2016, and averaged $292.8 million per year for the three-year period 2014 through 2016.

We periodically monitor our anticipated liquidity needs to ensure that our credit facility portfolio appropriately covers our anticipated needs. In October 2016, we renewed our $150 million bilateral credit facility for an additional two years, to October 2018.

At December 31, 2016, we had $1.6 billion of committed credit arrangements in place and $1.3 billion available under these facilities. The four separate facilities are reflected in the table below:

Committed Credit Facilities

(dollars in millions)

	Authorize Amount	Available 12/31/2016	Expiration Date
Unsecured Facilities:			
Syndicated Line among 13 banks led by CFC	$ 1,210	$ 972[(1)]	March 2020
CFC Line of Credit[(2)]	110	110	December 2018
JPMorgan Chase Line of Credit	150	34[(3)]	October 2018
Secured Facilities:			
CFC Term Loan[(2)]	250	250	December 2018

(1) Of the portion of this facility that was unavailable at 12/31/16, $102.2 million was dedicated to support outstanding commercial paper and $135.5 million related to letters of credit issued to support variable rate demand bonds.

(2) Any amounts drawn under the $110 million unsecured line of credit with CFC will reduce the amount that can be drawn under the $250 million secured term loan. Any amounts borrowed under the $250 million term loan would be secured under our first mortgage indenture, with a maturity no later than December 31, 2043.

(3) Of the portion of this facility that was unavailable at 12/31/16, $113.7 million related to letters of credit issued to support variable rate demand bonds and $2.2 million related to letters of credit issued to post collateral to third parties.

We have the flexibility to use the $1.2 billion syndicated line of credit for several purposes, including borrowing for general corporate purposes, to support up to $1.0 billion of commercial paper and to issue letters of credit to third parties.

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

Under our unsecured committed lines of credit, we have the ability to issue letters of credit totaling $760.0 million in the aggregate, of which $508.6 million remained available at December 31, 2016. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under our committed credit facilities for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue. The majority of our outstanding letters of credit are for the purpose of providing credit enhancement on variable rate demand bonds.

We are currently issuing commercial paper to provide interim funding for payments related to the construction of Vogtle Units No. 3 and No. 4 until advances for permanent funding under the Department of Energy loan are requested. The loan allows us to advance funds quarterly, however, for the last few years we have advanced funds semi-annually in June and December. For a discussion of the Plant Vogtle construction, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*." For a discussion of our permanent financing for Vogtle Units No. 3 and No. 4 see "– *Financing Activities*."

Between projected cash on hand and the credit arrangements currently in place, we believe we have sufficient liquidity to cover normal operations and our interim financing needs, including interim financing for the new Vogtle units, until long-term financing is obtained.

Two of our line of credit facilities contain similar financial covenants that require us to maintain minimum patronage capital levels. Currently, we are required to maintain minimum patronage capital of $675 million. As of December 31, 2016, our patronage capital balance was $859.8 million. These agreements contain an additional covenant that limits our secured indebtedness and our unsecured indebtedness, both as defined in the credit agreements, to $12 billion and $4 billion, respectively. At December 31, 2016, we had approximately $8.3 billion of secured indebtedness outstanding and $102.2 million of unsecured indebtedness outstanding.

Under a power bill prepayment program we offer, 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. We currently have 17 members participating in the program and a year-end balance of $225.1 million remaining to be applied against future power bills.

In addition to unrestricted available liquidity, at December 31, 2016 we had $468.1 million of restricted liquidity in connection with deposits made into a Rural Utilities Service Cushion of Credit Account. Deposits into the Cushion of Credit Account are voluntary and earn a rate of interest of 5% per annum. The funds in the account, including interest thereon, can only be applied to debt service on Rural Utilities Service notes and Rural Utilities Service-guaranteed Federal Financing Bank notes. From time to time we may deposit additional funds into the Cushion of Credit Account.

Liquidity Covenants. At December 31, 2016, we had only one financial agreement in place containing a liquidity covenant. This covenant is in connection with the Rocky Mountain lease transaction 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 2016 and expect to have sufficient liquidity to meet this covenant in 2017. For a discussion of the Rocky Mountain lease transaction, see Note 4 of Notes to Consolidated Financial Statements.

Financing Activities

First Mortgage Indenture. At December 31, 2016, we had $8.3 billion of outstanding debt secured equally and ratably under our first mortgage indenture, an increase of $729 million from December 31, 2015. A substantial portion of this increase relates to funds advanced under the Department of Energy-guaranteed Federal Financing Bank loan covering the construction cost of the new Vogtle units. From time to time, we may issue additional first mortgage obligations ranking equally and ratably with the existing first mortgage indenture obligations. The aggregate principal amount of obligations that may be issued under the first mortgage indenture is not limited; however, our ability to issue additional obligations under the first mortgage indenture is subject to certain requirements related to the certified value of certain of our tangible property, repayment of obligations outstanding under the first mortgage indenture and payments made under certain pledged contracts relating to property to be acquired.

Department of Energy-Guaranteed Loan. In 2014, we closed on a loan facility with the Department of Energy that we expect to fund up to $3.1 billion of the cost to construct our 30% undivided share of Vogtle Units

No. 3 and No. 4. The loan is being funded by the Federal Financing Bank and is backed by a federal loan guarantee provided by the Department of Energy. At December 31, 2016, we had advanced $1.7 billion under this loan and we had the capacity to fund an additional $475 million under the facility based on the amount of eligible project costs already incurred. We anticipate making draws under the Department of Energy loan on at least a semi-annual basis through 2020 to meet our funding requirements as construction progresses. All of the debt under this loan will be secured ratably with all other debt under our first mortgage indenture. Continued access to the committed funds under this loan requires us to meet certain conditions related to our business and the Vogtle project and also requires certain third-parties related to the Vogtle project to comply with certain laws. In addition, a failure by the Contractor to perform its obligations under the EPC Agreement could, under certain circumstances, impact our ability to make further advances under this loan and give the Department of Energy discretion to require that we repay all amounts outstanding under the loan over a five-year period. For additional information regarding this loan, see Note 7a of Notes to Consolidated Financial Statements.

In addition to the Department of Energy funding, we have issued $1.4 billion of first mortgage bonds to finance a substantial portion of the Vogtle expansion that will not be funded by the Department of Energy. As of December 31, 2016, we had funded in the aggregate approximately $3.1 billion of our Vogtle project cost. Depending on the final Vogtle project cost, and the final amount advanced under the Department of Energy-guaranteed loan, there may be a need for additional capital market financing.

Rural Utilities Service-Guaranteed Loans. At December 31, 2016 we had two approved Rural Utilities Service-guaranteed loans totaling $678 million that were in various stages of being drawn down, with $506 million remaining to be advanced. As of December 31, 2016, we had $2.6 billion of debt outstanding under various Rural Utilities Service-guaranteed loans, a decrease of $15.6 million from December 31, 2015.

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 ratably with all other debt under our first mortgage indenture.

Bond Financings. In April 2016, we issued $250 million of first mortgage bonds to provide long-term funding for expenditures related to the Vogtle construction project and the Smith Energy Facility. The bonds are secured ratably with all other debt under our first mortgage indenture.

In the fourth quarter of 2017, we plan to issue approximately $523 million of tax-exempt pollution control bonds, the proceeds of which will be used to refinance: i) $400 million of existing pollution control bonds that are callable on January 1, 2018, and ii) $123 million of commercial paper that was issued in January 2017 to temporarily refinance our remaining auction rate securities. When issued, we anticipate that the bonds will be secured ratably with all other debt under our first mortgage indenture.

Capital Requirements

Capital Expenditures. As part of our ongoing capital planning, we forecast expenditures required for generating facilities and other capital projects. The table below details these forecasts for 2017 through 2019. 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)

	2017	2018	2019	Total
Future Generation(2)	$ 486	$ 527	$ 380	$ 1,393
Existing Generation(3)	148	104	113	365
Environmental Compliance(4)	63	98	33	194
Nuclear Fuel(5)	65	96	73	234
General Plant	10	9	9	28
Total	$ 772	$ 834	$ 608	$ 2,214

(1) Includes allowance for funds used during construction.

(2) Relates to construction of Vogtle Units No. 3 and No. 4, excluding initial nuclear fuel core. Forecasted expenditures are based on assumed in-service dates of December 2019 for Vogtle Unit No. 3 and September 2020 for Vogtle Unit No. 4.

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

(4) Pollution control equipment and facilities being installed at coal-fired Plants Scherer and Wansley, including to comply with coal ash regulations.

(5) Includes nuclear fuel on existing nuclear units and initial nuclear fuel core for Vogtle Units No. 3 and No. 4.

In addition to the amounts reflected in the table above, we have budgeted approximately $300 million to complete construction of Vogtle Units No. 3 and No. 4

beyond the years shown in the table. In the event that the Contractor is unable to meet the revised forecasted in-service dates of December 2019 for Unit No. 3 and December 2020 for Unit No. 4, we anticipate that each month of additional delay in the near term will cost us approximately $20 million, including financing and owner's costs, net of liquidated damages. Further, the failure of the Westinghouse or Toshiba to perform its obligations under the EPC Agreement or related Toshiba parent guarantee, respectively, could have a material impact on our costs for Vogtle Units No. 3 and No. 4. For information regarding this project, see "BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Plant Vogtle Units No. 3 and No. 4*" and "– *Financing Activities.*"

We are currently subject to extensive environmental regulations and may be subject to future additional environmental regulations, including future implementation of existing laws and regulations. Since alternative legislative and regulatory environmental compliance programs continue to be debated on a national level, we cannot predict what capital costs may ultimately be required. Therefore, environmental expenditures included in the above table only include amounts related to budgeted projects to comply with existing and certain well-defined rules and regulations and do not include amounts related to compliance with other, less certain rules, such as the Clean Power Plan, which was recently stayed by the U.S. Supreme Court.

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 – REGULATION – Environmental."

Contractual Obligations. The table below reflects, as of December 31, 2016, our contractual obligations for the periods indicated.

Contractual Obligations
(dollars in millions)

	2017	2018-2019	2020-2021	Beyond 2021	Total
Long-Term Debt:					
Principal[1]	$ 310	$ 755	$ 575	$ 6,835	$ 8,475
Interest[2]	325	560	626	4,217	5,728
Capital Leases[3]	22	30	31	100	183
Operating Leases	5	8	1	–	14
Rocky Mtn.Lease Transaction[4]	–	–	–	38	38
Chattahoochee O&M Agmts.	24	22	–	–	46
Asset Retirement Obligations[5]	5	18	34	2,926	2,983
Purchase Commitments[6]	117	201	172	878	1,368
Total	**$ 808**	**$ 1,594**	**$ 1,439**	**$ 14,994**	**$ 18,835**

(1) Includes principal amounts that would be due if the credit support facilities for the Series 2009 and Series 2010 pollution control bonds were drawn upon and became payable in accordance with their terms, such as would occur if the credit facility providing the support were not renewed or extended at its expiration date. These amounts equal $56 million in 2018, $37 million in 2019 and $152 million in 2020. We anticipate extending these credit facilities before their expirations. The nominal maturities of the Series 2009 and Series 2010 pollution control bonds range from 2030 through 2038.
(2) Includes interest expense related to variable rate debt. Future variable rates are based on projected LIBOR and SIFMA interest rate curves as of February 2017.
(3) Amounts represent total rental payment obligations, not amortization of debt underlying the leases.
(4) We have entered into an Equity Funding Agreement for a third party to fund this obligation.
(5) A substantial portion of this amount relates to the decommissioning of nuclear facilities.
(6) Includes commitments for the procurement of coal and nuclear fuel and natural gas related transportation agreements. Contracts for coal and nuclear fuel procurement, in most cases, contain provision for price escalations, minimum purchase levels and other financial commitments.

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.

Credit Rating Risk

The table below sets forth our current ratings from S&P Global Ratings (formerly known as Standard & Poor's Ratings), Moody's Investors Service and Fitch Ratings.

Our Ratings	**S&P**	**Moody's**	**Fitch**
Long-term ratings:			
Senior secured rating	A	Baa1	A
Issuer/unsecured rating[1]	A	Baa2	N/R[2]
Rating outlook	Negative	Negative	Negative
Short-term rating:			
Commercial paper rating	A-1	P-2	F1

(1) We currently have no long-term debt that is unsecured.

(2) N/R indicates no rating assigned for this 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, 2016, our maximum potential collateral requirements were as follows:

At senior secured rating levels:

- a total of approximately $50 million at a senior secured level of BBB-/Baa3,
- a total of approximately $185 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured or issuer rating levels:

- a total of approximately $0.3 million at a senior unsecured or issuer level of BBB-/Baa3,
- a total of approximately $57 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 two of our line of credit agreements are based on credit ratings and could increase if our ratings are lowered. None of these covenants and provisions, however, would result in acceleration of any debt due to credit rating downgrades.

Given our current level of ratings, our management does not have any reason to expect a downgrade that would result in any material impacts to our business. However, our ratings reflect only the views of the rating agencies and we cannot give any assurance that our ratings will be maintained at current levels for any period of time.

Off-Balance Sheet Arrangements

We do not currently have any material off-balance sheet arrangements.

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.

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

Interest Rate Risk

At December 31, 2016, we were exposed to the risk of changes in interest rates related to our $473 million of variable rate debt, which includes $102 million of commercial paper outstanding (which typically has maturities of between 1 and 90 days) and $368 million of pollution control bond debt (including variable rate demand bonds subject to repricing weekly and auction rate securities subject to repricing every 35 days). At December 31, 2016, the weighted average interest rate on this variable rate debt was 0.91%. If, during 2016, 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 $6 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. At December 31, 2016, we had 5.6% of our total debt, including commercial paper, in a variable rate mode.

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

In addition to interest rate risk on existing debt, we are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4. We previously purchased out-of-the money interest rate options to hedge the risk of rising interest rates related to the financing of the new Vogtle units. These interest rate options have largely expired and the last of these options expires on March 31, 2017. Like all of the previously expired options, we expect this option to expire without value. For additional information regarding our interest rate options, see Note 3 of Notes to Consolidated Financial Statements.

Equity Price Risk

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

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

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

A 10% decline in the value of the internal and external funds' equity securities as of December 31, 2016 would result in a loss of value to the funds of approximately $29 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. Our existing contracts and stockpiles will provide fixed prices for up to 100% and 89% of our remaining 2017 forecasted coal requirements at Plants Scherer and Wansley, respectively.

The objective of our coal procurement strategy is to ensure reliable coal supply and some price stability for our members. Our strategy permits 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 or operate eight gas fired generation facilities totaling 4,170 megawatts of nameplate capacity. See "PROPERTIES – Generating Facilities" and "BUSINESS – OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Smarr EMC*."

We maintain a natural gas hedge program, which assists our participating members in managing potential fluctuations in our power rates to them due to changes in the market price of natural gas. Currently, approximately 18 of our members have elected to participate in our natural gas hedging program. This program layers in fixed prices for a portion of our forecasted natural gas requirements over a rolling time horizon of up to five years. Natural gas swap arrangements are used for hedging under this program. Under our 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. The fair value of the swaps at December 31, 2016 was approximately $15.1 million which represents the net amount we would have received if the swaps had been terminated as of that date. As of December 31, 2016, approximately 30% of our 2017 total system forecasted natural gas requirements were hedged under swap arrangements. A hypothetical 10% decline in the market price of natural gas would have resulted in a decrease of approximately $21.5 million to the fair value of our natural gas swap agreements. Additional members may elect to participate in our natural gas hedging program, and participating members may choose to discontinue their participation in this program 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.

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, 2016, 2015 and 2014

	(dollars in thousands)		
	2016	2015	2014
Operating revenues:			
Sales to Members	**$ 1,506,807**	$ 1,219,052	$ 1,314,869
Sales to non-Members	**424**	130,773	93,294
Total operating revenues	**1,507,231**	1,349,825	1,408,163
Operating expenses:			
Fuel	**513,258**	441,738	515,729
Production	**434,306**	457,264	428,801
Depreciation and amortization	**217,534**	168,920	166,247
Purchased power	**54,108**	56,925	71,799
Accretion	**32,361**	26,108	24,616
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**–**	(58,588)	(58,426)
Total operating expenses	**1,251,567**	1,092,367	1,148,766
Operating margin	**255,664**	257,458	259,397
Other income:			
Investment income	**51,656**	40,424	36,791
Amortization of deferred gains	**1,788**	1,788	1,788
Allowance for equity funds used during construction	**788**	675	1,172
Other	**2,671**	9,143	6,620
Total other income	**56,903**	52,030	46,371
Interest charges:			
Interest expense	**366,892**	354,269	344,561
Allowance for debt funds used during construction	**(116,634)**	(108,667)	(102,081)
Amortization of debt discount and expense	**11,964**	15,545	16,653
Net interest charges	**262,222**	261,147	259,133
Net margin	**$ 50,345**	$ 48,341	$ 46,635

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE MARGIN
For the years ended December 31, 2016, 2015 and 2014

	(dollars in thousands)		
	2016	2015	2014
Net Margin	**$ 50,345**	$ 48,341	$ 46,635
Other comprehensive margin:			
Unrealized (loss) gain on available-for-sale securities	**(428)**	(410)	1,017
Total comprehensive margin	**$ 49,917**	$ 47,931	$ 47,652

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2016 and 2015

	(dollars in thousands)	
	2016	2015
Assets		
Electric plant:		
In service	**$ 8,786,839**	$ 8,596,148
Less: Accumulated provision for depreciation	**(4,115,339)**	(3,925,838)
	4,671,500	4,670,310
Nuclear fuel, at amortized cost	**377,653**	373,145
Construction work in progress	**3,228,214**	2,868,669
Total electric plant	**8,277,367**	7,912,124
Investments and funds:		
Nuclear decommissioning trust fund	**386,029**	363,829
Investment in associated companies	**72,783**	72,010
Long-term investments	**99,874**	86,771
Restricted cash and investments	**221,122**	134,690
Other	**20,730**	19,097
Total investments and funds	**800,538**	676,397
Current assets:		
Cash and cash equivalents	**366,290**	213,038
Restricted short-term investments	**247,006**	253,204
Receivables	**155,042**	130,464
Inventories, at average cost	**259,831**	299,252
Prepayments and other current assets	**32,919**	16,913
Total current assets	**1,061,088**	912,871
Deferred charges and other assets:		
Regulatory assets	**545,387**	530,254
Prepayments to Georgia Power Company	**3,948**	17,801
Other	**12,785**	10,336
Total deferred charges	**562,120**	558,391
Total assets	**$10,701,113**	$10,059,783

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2016 and 2015

	(dollars in thousands)	
	2016	2015
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 859,810**	$ 809,465
Accumulated other comprehensive (deficit) margin	**(370)**	58
	859,440	809,523
Long-term debt	**7,892,836**	7,291,154
Obligations under capital leases	**92,096**	96,501
Other	**18,765**	17,561
Total capitalization	**8,863,137**	8,214,739
Current liabilities:		
Long-term debt and capital leases due within one year	**316,861**	189,840
Short-term borrowings	**102,168**	261,478
Accounts payable	**73,801**	157,432
Accrued interest	**93,634**	58,830
Member power bill prepayments, current	**176,988**	174,743
Other current liabilities	**59,979**	86,746
Total current liabilities	**823,431**	929,069
Deferred credits and other liabilities:		
Asset retirement obligations	**698,051**	602,230
Member power bill prepayments, non-current	**48,115**	44,205
Contract retainage	**40,008**	66,515
Regulatory liabilities	**197,748**	166,967
Other	**30,623**	36,058
Total deferred credits and other liabilities	**1,014,545**	915,975
Total equity and liabilities	**$10,701,113**	$10,059,783
Commitments and Contingencies (Notes 1, 7, 10, 11, 12 and 13)		

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31, 2016 and 2015

	(dollars in thousands)	
	2016	2015
Secured Long-term debt:		
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 1.84% to 8.43% (average rate of 4.09% at December 31, 2016) due in quarterly installments through 2043	**$ 2,581,281**	$ 2,596,912
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 2.51% to 3.87% (average rate of 3.36% at December 31, 2016) due in quarterly installments through 2044	**1,678,442**	1,180,628
First mortgage notes payable to National Rural Utilities Cooperative Finance Corporation at interest rates varying from 4.35% to 4.90% (average rate of 4.60% at December 31, 2016) due in quarterly installments through 2020	**3,347**	4,238
First mortgage bonds payable:		
• Series 2006 First Mortgage Bonds, 5.534%, due 2031 through 2035	**300,000**	300,000
• Series 2007 First Mortgage Bonds, 6.191%, due 2024 through 2031	**500,000**	500,000
• Series 2009A First Mortgage Bonds, 6.10%, due 2019	**350,000**	350,000
• Series 2009B First Mortgage Bonds, 5.95%, due 2039	**400,000**	400,000
• Series 2009 Clean renewable energy bond, 1.81%, due 2024	**8,083**	9,093
• Series 2010A First Mortgage Bonds, 5.375% due 2040	**450,000**	450,000
• Series 2011A First Mortgage Bonds, 5.25% due 2050	**300,000**	300,000
• Series 2012A First Mortgage Bonds, 4.20% due 2042	**250,000**	250,000
• Series 2014A First Mortgage Bonds, 4.55% due 2044	**250,000**	250,000
• Series 2016 First Mortgage Bonds, 4.25% due 2046	**250,000**	–
First mortgage notes issued in connection with the sale of pollution control revenue bonds through the Development Authorities of Appling, Burke, Heard and Monroe Counties, Georgia:		
• Series 2003A Burke, Heard, Monroe and 2003B Burke Auction rate bonds, 1.24%, due 2024	**95,230**	95,230
• Series 2004 Burke and Monroe Auction rate bonds, 1.35%, due 2020	**11,525**	11,525
• Series 2005 Burke and Monroe Auction rate bonds, 1.06%, due 2040	**15,865**	15,865
• Series 2008A through 2008C 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 2009A Heard and Monroe, and 2009B Monroe Weekly rate bonds, 0.73% to 0.76%, due 2030 through 2038	**112,055**	112,055
• Series 2010A Burke and Monroe, and 2010B Burke Weekly rate bonds, 0.72% to 0.73%, due 2036 through 2037	**133,550**	133,550
• Series 2013A Appling, Burke and Monroe Term rate bonds, 2.40% through April 1, 2020, due 2038 through 2040	**212,760**	212,760
CoBank, ACB notes payable:		
• Transmission first mortgage notes payable: variable at 2.65% to 3.75% through January 31, 2017, due in bimonthly installments through November 1, 2018	**419**	595
• Transmission first mortgage notes payable: variable at 2.65% to 3.75% through January 31, 2017, due in bimonthly installments through September 1, 2019	**2,181**	2,791
Total Secured Long-term debt	**$ 8,304,523**	$ 7,575,027
Obligations under capital leases	**98,531**	100,456
Obligation under Rocky Mountain transactions	**18,765**	17,561
Patronage capital and membership fees	**859,810**	809,465
Accumulated other comprehensive (deficit) margin	**(370)**	58
Subtotal	**9,281,259**	8,502,567
Less: long-term debt and capital leases due within one year	**(316,861)**	(189,840)
Less: unamortized debt issuance costs	**(93,133)**	(93,651)
Less: unamortized bond discounts on long-term debt	**(8,128)**	(4,337)
Total capitalization	**$ 8,863,137**	$ 8,214,739

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, 2016, 2015 and 2014

	(dollars in thousands)		
	2016	2015	2014
Cash flows from operating activities:			
Net margin	**$ 50,345**	$ 48,341	$ 46,635
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	**362,716**	313,320	313,449
Accretion cost	**32,361**	26,108	24,616
Amortization of deferred gains	**(1,788)**	(1,788)	(1,788)
Allowance for equity funds used during construction	**(788)**	(675)	(1,172)
Deferred outage costs	**(40,599)**	(40,803)	(53,823)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**0**	(58,588)	(58,426)
Loss (gain) on sale of investments	**96**	(34,464)	(18,179)
Regulatory deferral of costs associated with nuclear decommissioning	**(20,440)**	21,532	4,564
Other	**(7,286)**	(8,353)	(8,835)
Change in operating assets and liabilities:			
Receivables	**(24,578)**	(98)	(1,000)
Inventories	**23,947**	(28,403)	15,319
Prepayments and other current assets	**(2,172)**	(4,317)	3,197
Accounts payable	**(76,495)**	(37,155)	(22,488)
Accrued interest	**34,804**	(11)	648
Accrued and withheld taxes	**1,102**	3,731	(4,198)
Other current liabilities	**(11,937)**	2,805	8,956
Member power bill prepayments	**6,155**	20,994	83,236
Total adjustments	**275,098**	173,835	284,076
Net cash provided by operating activities	**325,443**	222,176	330,711
Cash flows from investing activities:			
Property additions	**(613,019)**	(495,426)	(534,171)
Activity in nuclear decommissioning trust fund – Purchases	**(395,506)**	(558,568)	(389,854)
– Proceeds	**389,011**	553,654	385,185
Increase in restricted cash and investments	**(86,432)**	(16,301)	(57,815)
Decrease (increase) in restricted short-term investments	**6,198**	(6,076)	48
Activity in other long-term investments – Purchases	**(61,200)**	(89,263)	(54,113)
– Proceeds	**50,529**	86,563	53,756
Activity on interest rate options – Purchases/Collateral returned	**0**	0	(81,070)
– Collateral received	**0**	0	46,100
Other	**13,554**	(13,068)	(44,893)
Net cash used in investing activities	**(696,865)**	(538,485)	(676,827)
Cash flows from financing activities:			
Long-term debt proceeds	**790,385**	423,637	1,135,687
Long-term debt payments	**(114,702)**	(162,903)	(408,377)
(Decrease) increase in short-term borrowings, net	**(159,310)**	27,109	(510,038)
Other	**8,301**	4,113	(41,958)
Net cash provided by financing activities	**524,674**	291,956	175,314
Net increase (decrease) in cash and cash equivalents	**153,252**	(24,353)	(170,802)
Cash and cash equivalents at beginning of period	**213,038**	237,391	408,193
Cash and cash equivalents at end of period	**$ 366,290**	$ 213,038	$ 237,391
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	**$ 212,574**	$ 240,817	$ 237,107
Supplemental disclosure of non-cash investing and financing activities:			
Change in asset retirement obligations	**$ 63,011**	$ 144,161	$ –
Change in accrued property additions	**$ (50,775)**	$ 119,775	$ 36,633
Interest paid-in-kind	**$ 47,814**	$ 36,021	$ 24,607

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) MARGIN

For the years ended December 31, 2016, 2015 and 2014

	(dollars in thousands)		
	Patronage Capital and Membership Fees	Accumulated Other Comprehensive (Deficit) Margin	Total
Balance at December 31, 2013	$ 714,489	$ (549)	$ 713,940
Components of comprehensive margin in 2014			
Net margin	46,635	–	46,635
Unrealized gain on available-for-sale securities	–	1,017	1,017
Total comprehensive margin			47,652
Balance at December 31, 2014	$ 761,124	$ 468	$ 761,592
Components of comprehensive margin in 2015			
Net margin	48,341	–	48,341
Unrealized loss on available-for-sale securities	–	(410)	(410)
Total comprehensive margin			47,931
Balance at December 31, 2015	$ 809,465	$ 58	$ 809,523
Components of comprehensive margin in 2016			
Net margin	50,345	–	50,345
Unrealized loss on available-for-sale securities	–	(428)	(428)
Total comprehensive margin			49,917
Balance at December 31, 2016	$ 859,810	$ (370)	$ 859,440

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, Georgia that operates on a not-for-profit basis. We are owned by 38 retail electric distribution cooperative members in Georgia. We provide wholesale electric power from a combination of owned and co-owned generating units of which our ownership share totals 7,809 megawatts of summer planning reserve capacity. We also manage and operate Smarr EMC which owns 728 megawatts of summer planning reserve capacity. Georgia Power Company is a co-owner and the operating agent of our nuclear and coal-fired generating units. Our members in turn distribute energy on a retail basis to approximately 4.1 million people.

b. Basis of accounting

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

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

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of December 31, 2016 and 2015 and the reported amounts of revenues and expenses for each of the three years in the period ended December 31, 2016. 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 $190 in membership fees. Patronage capital includes retained net margin. Any excess of revenues over expenditures from operations is treated as an advance of capital by our members and is allocated to each member on the basis of their fixed percentage capacity cost responsibilities in our generation.

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

d. Accumulated other comprehensive (deficit) margin

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

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

Accumulated Other Comprehensive (Deficit) Margin

	(dollars in thousands) Available-for-sale Securities
Balance at December 31, 2013	$ (549)
Unrealized gain	1,180
(Gain) reclassified to net margin	(163)
Balance at December 31, 2014	468
Unrealized gain	265
(Gain) reclassified to net margin	(675)
Balance at December 31, 2015	58
Unrealized loss	(234)
(Gain) reclassified to net margin	(194)
Balance at December 31, 2016	**$ (370)**

e. Margin policy

We are required under our first mortgage indenture to produce a margins for interest ratio of at least 1.10 for each fiscal year. For the years 2016, 2015 and 2014, we achieved a margins for interest ratio of 1.14.

f. Operating revenues

Electricity revenues are recognized when capacity and energy are provided. Operating revenues from sales to members consist primarily of electricity sales pursuant to long-term wholesale power contracts which we maintain with each of our members. These wholesale power contracts obligate each member to pay us for capacity and energy furnished in accordance with rates we establish. Capacity revenues recover our fixed costs plus a targeted margin and are charged regardless of whether our generation and purchased power resources are dispatched to produce electricity. Capacity revenues are based on an annual budget and, notwithstanding budget adjustments to meet our targeted margin, are recorded in approximately equal amounts throughout the year. Energy revenues recover variable costs, such as fuel, incurred to generate or purchase electricity and are recorded such that energy revenues equal the actual energy costs incurred.

Prior to 2016, operating revenues from sales to non-members consisted primarily of energy sales at Smith.

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2016, 2015 or 2014:

	2016	2015	2014
Jackson EMC	**14.3%**	9.7%	10.4%
Cobb EMC	**13.7%**	13.1%	13.6%
Sawnee EMC	**10.5%**	10.4%	9.5%

We have a rate management program that allows us to expense and recover certain costs on a current basis that would otherwise be deferred or capitalized. The subscribing members of Vogtle Units No. 3 and No. 4 can elect to participate in this program on an annual basis. The Vogtle program allows for the recovery of financing costs associated with the construction of Vogtle Units No. 3 and No. 4 on a current basis. Under this program, amounts billed to participating members in 2016, 2015 and 2014 were $16,096,000, $7,630,000 and $6,182,000, respectively. Prior to 2016, members also subscribed to the Smith program, which allowed for the accelerated recovery of deferred net costs related to Smith. The Smith program ceased as of December 31, 2015 when the plant became available for scheduling to our members. Amounts billed to participating members under this program were $17,745,000 and $8,809,000 in 2015 and 2014, respectively.

g. Receivables

A substantial portion of our receivables are related to electricity sales to our members. These 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, plus a margin requirement. Member receivables at December 31, 2016 and 2015 were $136,552,000 and $108,729,000, respectively. The remainder of our receivables is primarily related to transactions with affiliated companies, electricity sales to non-members (2015) and to interest income on investments. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period the amounts are determined to be uncollectible.

h. Nuclear fuel cost

The cost of nuclear fuel is being amortized to fuel expense based on usage. The total nuclear fuel expense for 2016, 2015 and 2014 amounted to $83,751,000, $78,762,000, and $85,166,000, respectively.

Contracts with the U.S. Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at Plants Hatch and Vogtle. The Department of Energy failed to begin disposing of spent fuel in January 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants has pursued and continues to pursue legal remedies against the Department of Energy for breach of contract.

On December 14, 2014, the U.S. Court of Federal Claims issued a judgment in favor of Georgia Power, as agent for the co-owners, to recover spent nuclear fuel storage costs at Plant Hatch and Vogtle Units No. 1 and No. 2 covering the period of 2005 through 2010. Our ownership share of the $36,474,000 total award was $10,949,000, which was received in April 2015. The effects of the award were recorded during the first quarter of 2015 and resulted in a $7,320,000 reduction in total operating expenses, including reductions to fuel expense and production costs, as well as a $3,629,000 reduction to plant in service.

On March 4, 2014, Georgia Power, as agent for the co-owners, filed a separate claim seeking damages for spent nuclear fuel storage costs at Plant Hatch and Vogtle Units No. 1 and No. 2 covering a period of January 1, 2011 through December 31, 2013. The damage period was subsequently amended and now extends through December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts were recognized in the financial statements as of December 31, 2016 for this claim. The final outcome of these matters cannot be determined at this time.

Both Plants Hatch and Vogtle have on-site dry spent storage facilities in operation. Facilities at both plants can be expanded to accommodate spent fuel through the expected life of each plant.

i. Asset retirement obligations and other retirement costs

Asset retirement obligations are legal obligations associated with the retirement of long-lived assets. These obligations represent the present value of the estimated costs for an asset's future retirement discounted using a credit-adjusted risk-free rate, and are recorded in the period in which the liability is incurred. The liabilities we have recognized primarily relate to the decommissioning of our nuclear facilities. In addition, we have retirement obligations related to coal ash ponds, gypsum cells, powder activated carbon cells, landfill sites and asbestos removal. Under the accounting provision for regulated operations, we record a regulatory asset or liability to reflect the difference in timing of recognition of the costs related to nuclear and coal ash related decommissioning for financial statement purposes and for ratemaking purposes.

Periodically, we obtain revised cost studies associated with our nuclear and fossil plants' asset retirement obligations. Actual retirement costs may vary from these estimates. The estimated costs of nuclear and coal ash pond decommissioning are based on the most recent studies performed in 2015 and 2016, respectively.

The following table reflects the details of the Asset Retirement Obligations included in the consolidated balance sheets for the years 2016 and 2015.

(dollars in thousands)

	Nuclear	**Coal Ash Pond**	**Other**	**Total**
Balance at December 31, 2015	$ 488,458	$ 93,622	$ 20,150	$ 602,230
Liabilities settled	**–**	**(553)**	**(707)**	**(1,260)**
Accretion	**29,107**	**2,215**	**1,039**	**32,361**
Change in Cash Flow Estimates	**–**	**61,181**	**3,539**	**64,720**
Balance at December 31, 2016	**$ 517,565**	**$ 156,465**	**$ 24,021**	**$ 698,051**

(dollars in thousands)

	Nuclear	Coal Ash Pond	Other	Total
Balance at December 31, 2014	$ 369,046	$ 42,609	$ 20,605	$ 432,260
Liabilities settled	–	–	(299)	(299)
Accretion	23,231	1,929	948	26,108
Change in Cash Flow Estimates	96,181	49,084	(1,104)	144,161
Balance at December 31, 2015	$ 488,458	$ 93,622	$ 20,150	$ 602,230

Nuclear Decommissioning. 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, as well as the management of spent fuel. We do not have a legal obligation to decommission non-radiated structures and, therefore, these costs are excluded from the related asset retirement obligation and the amounts in the table above. Actual decommissioning costs may vary from these estimates because of, but not limited to, changes in the assumed date of decommissioning, changes in regulatory requirements, changes in technology, and changes in costs of labor, materials and equipment. The estimated costs of decommissioning are based on the most current study performed in 2015. In projecting future costs, the escalation rate for labor, materials and equipment was assumed to be 2.5%. The increase in the cash flow estimates in 2015 was primarily attributable to security costs, waste disposal costs and inflation, among other factors. Our portion of the estimated costs of decommissioning co-owned nuclear facilities were as follows:

	(dollars in thousands)			
2015 site study	Hatch Unit No. 1	Hatch Unit No. 2	Vogtle Unit No. 1	Vogtle Unit No. 2
Expected start date of decommissioning	2034	2038	2047	2049
Estimated costs based on site study in 2015 dollars:				
Radiated structures	$ 193,000	$ 213,000	$ 178,000	$ 195,000
Spent fuel management	49,000	47,000	49,000	47,000
Non-radiated structures	16,000	22,000	26,000	33,000
Total estimated site study costs	$ 258,000	$ 282,000	$ 253,000	$ 275,000

We have established funds to comply with the Nuclear Regulatory Commission regulations regarding the decommissioning of our nuclear plants. See Note 1j for information regarding the nuclear decommissioning funds.

Coal Ash Pond. On April 17, 2015 the Environmental Protection Agency published its final coal combustion residuals (CCR) rule which regulates CCRs as non-hazardous materials under Subtitle D of the Resource Conservation and Recovery Act. The rule took effect on October 19, 2015. Our most current assessment of the final CCR rule resulted in a $59,472,000 change in cash flow estimates for coal ash pond decommissioning. Estimates are based on various assumptions including, but not limited to, closure and post-closure cost estimates, timing of expenditures, escalation factors, discount rates and methods for complying with the CCR rule. The 2016 increase in cash flow estimates was primarily attributed to an increase in the closure cost estimates. The increase in the cash flow estimates in 2015 was a result of changes in the assumptions regarding the timing of expenditures as well as an increase in the cost estimates. Additional adjustments to the asset retirement obligations are expected periodically as we continue to assess the impact of the rule on our estimates and assumptions.

Other. Accounting standards for asset retirement and environmental obligations do not apply to a retirement cost for which there is no legal obligation to retire the asset, and non-regulated entities are not allowed to accrue for such future retirement costs. We continue to recognize retirement costs for these other obligations in our depreciation rates under the accounting provisions for regulated operations. Accordingly, the accumulated retirement costs for other obligations are reflected as a regulatory liability in our balance sheets. For information regarding accumulated retirement costs for other obligations, see Note 1r.

j. Nuclear decommissioning funds

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. The NRC definition of decommissioning does not include all costs that may be associated with decommissioning, such as spent fuel management and non-radiated structures. We have established external trust funds to comply with the NRC's regulations. Upon approval by the NRC, any funding in the external trust in excess of their requirements may be used for other decommissioning costs. In 2016 and 2015, no additional amounts were contributed to the external trust funds. These funds are managed by unrelated third party investment managers with the discretion to buy, sell and invest pursuant to investment objectives and restrictions set forth in agreements entered into between us and the investment managers. We record the investment securities held in the nuclear decommissioning trust fund, which are classified as available-for-sale, at fair value, as disclosed in Note 2. Because day-to-day investment decisions are made by third party investment managers, the ability to hold investments in unrealized loss positions is outside our control.

In addition to the external trust funds, we maintain unrestricted investments internally designated for nuclear decommissioning. These internal funds are available to be utilized to fund the external trust funds, should additional funding be required, as well as other decommissioning costs outside the scope of the NRC funding regulations. The funds are included in long-term investments on our consolidated balance sheet. During 2016 and 2015, member collections of $4,750,000, respectively were contributed into the internal funds.

The following table outlines the fair value of our nuclear decommissioning funds as of December 31, 2016 and December 31, 2015. The funds are invested in a diversified mix of approximately 60% equity and 40% fixed income securities for both 2016 and 2015.

External Trust Funds:	2016				
	12.31.15 Cost	Purchases	Net Proceeds[1]	Unrealized Gain(Loss)	12.31.16 FV
Equity	$ 198,265	$ 46,865	$ (43,395)	$ 38,749	$ 240,484
Debt	144,187	347,383	(343,040)	(1,675)	$ 146,855
Other	187	1,258	(2,754)	(1)	$ (1,310)
Total	$ 342,639	$ 395,506	$ (389,189)	$ 37,073	$ 386,029

Internal Funds:	12.31.15 Cost	Purchases	Net Proceeds[1]	Unrealized Gain(Loss)	12.31.16 FV
Equity	$ 33,513	$ 0	$ 5,285	$ 7,263	$ 46,061
Debt	25,539	42,783	(42,115)	(211)	$ 25,996
Total	$ 59,052	$ 42,783	$ (36,830)	$ 7,052	$ 72,057

(1) Also included in net proceeds are net realized gains or losses, interest income and dividends, contributions and fees of $12,270,144.

External Trust Funds:	2015				
	12.31.14 Cost	Purchases	Net Proceeds[2]	Unrealized Gain(Loss)	12.31.15 FV
Equity	$ 183,527	$ 104,417	$ (77,504)	$ 23,321	$ 233,761
Debt	130,407	454,072	(450,747)	(2,128)	$ 131,604
Other	324	79	(1,935)	(4)	$ (1,536)
Total	$ 314,258	$ 558,568	$ (530,186)	$ 21,189	$ 363,829

Internal Funds:	12.31.14 Cost	Purchases	Net Proceeds[2]	Unrealized Gain(Loss)	12.31.15 FV
Equity	$ 19,796	$ 0	$ 13,717	$ 4,537	$ 38,050
Debt	22,767	82,554	(79,782)	(263)	$ 25,276
Total	$ 42,563	$ 82,554	$ (66,065)	$ 4,274	$ 63,326

(2) Also included in net proceeds are net realized gains or losses, interest income and dividends, contributions and fees of $44,871,375.

Realized and unrealized gains and losses of the nuclear decommissioning funds that would be recorded in earnings or other comprehensive margin (deficit) by a non-regulated entity are directly deducted from or added to the regulatory asset or liability for asset retirement obligations in accordance with our rate-making treatment.

Since inception in 1990 through 2016, the nuclear decommissioning trust fund has produced an average annualized return of approximately 5.9%. Based on current funding and cost study estimates, we expect the current balances and anticipated investment earnings of our decommissioning fund assets to be sufficient to meet all of our future nuclear decommissioning costs. Notwithstanding the above assumption, 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. We use standard depreciation rates as well as site specific rates determined through depreciation studies as approved by the Rural Utilities Service. The 2016 depreciation rates for steam and nuclear production in the table below reflect revised rates from depreciation rate studies completed in 2015. Site specific depreciation studies are performed every five years. Annual depreciation rates in effect in 2016, 2015 and 2014 were as follows:

	Range of Useful Life in years*	**2016**	2015	2014
Steam production	49-65	**2.84%**	1.93%	1.86%
Nuclear production	37-60	**1.96%**	1.55%	1.53%
Hydro production	50	**2.00%**	2.00%	2.00%
Other production	27-33	**2.55%**	2.38%	2.56%
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 2016.

Depreciation expense for the years 2016, 2015 and 2014 was $211,282,000, $180,866,000, and $178,302,000, respectively.

l. Electric plant

Electric plant is stated at original cost, which is the cost of the plant when first dedicated to public service, including acquisition adjustments, if any, plus the cost of any subsequent additions. Cost includes an allowance for the cost of equity and debt funds used during construction and allocable overheads. For the years ended 2016, 2015 and 2014, the allowance for funds used during construction rates were 4.61%, 4.73% and 4.97%, respectively.

Replacements and renewals of items considered to be units of property, the lowest level of property for which we capitalize, 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. Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are charged to expense, including certain major maintenance costs at our natural gas-fired plants.

m. Cash and cash equivalents

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

n. Restricted cash and investments

Restricted cash and investments primarily consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted investments can only be utilized for future Rural Utilities Service-guaranteed Federal Financing Bank debt service payments; deposits can also be used for debt service payments on direct loans made by the Rural Utilities Service but we no longer have such direct loans. The funds on deposit earn interest at a rate of 5% per annum. At December 31, 2016 and 2015, we had restricted cash and investments totaling $468,179,000 and $387,961,000, respectively, of which $221,122,000 and $134,690,000, respectively was classified as long-term. The funds on deposit with the Rural Utilities Service in the Cushion of Credit Account are held by the U.S. Treasury, acting through the Federal Financing Bank.

o. Inventories

We maintain inventories of fossil fuel and spare parts, including materials and supplies for our generation plants. These inventories are stated 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. The spare parts inventories primarily include the direct cost of generating plant spare parts. The spare parts inventory is carried at weighted average cost and the parts are charged to expense or capitalized, as appropriate when installed.

At December 31, 2016 and December 31, 2015, fossil fuels inventories were $57,289,000 and $104,086,000, respectively. Inventories for spare parts at 2016 and 2015 were $202,542,000 and $195,166,000, respectively.

p. Deferred charges and other assets

Prepayments to Georgia Power Company primarily represent progress payments for equipment associated with future nuclear refueling outages.

For a discussion regarding regulatory assets, see Note 1r.

q. Deferred credits and other liabilities

We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills monthly and are recorded as a reduction to member revenues. The prepayments are being credited against members' power bills through July 2021, with the majority of the balance scheduled to be credited by the end of 2017.

In connection with the Vogtle Units No. 3 and No. 4 construction project, we are accruing long-term contract retainage amounts for substantial and mechanical milestones that will become due near the anticipated commercial operation dates of the units. For more information regarding the Vogtle construction project, see Note 8.

r. Regulatory assets and liabilities

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

	(dollars in thousands)	
	2016	2015
Regulatory Assets:		
Premium and loss on reacquired debt[(a)]	**$ 55,084**	$ 61,916
Amortization on capital leases[(b)]	**32,274**	30,253
Outage costs[(c)]	**39,986**	42,027
Interest rate swap termination fees[(d)]	**3,570**	5,355
Asset Retirement Obligations – Ashpond and other[(l)]	**33,747**	1,098
Depreciation expense[(e)]	**44,091**	45,514
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs[(f)]	**43,444**	37,646
Interest rate options cost[(g)]	**107,394**	102,554
Deferral of effects on net margin – Smith Energy Facility[(h)]	**172,399**	178,343
Other regulatory assets[(m)]	**13,398**	25,548
Total Regulatory Assets	**545,387**	530,254
Regulatory Liabilities:		
Accumulated retirement costs for other obligations[(i)]	**$ 9,829**	$ 8,910
Deferral of effects on net margin – Hawk Road Energy Facility[(h)]	**20,163**	20,775
Major maintenance reserve[(j)]	**28,379**	22,422
Amortization on capital leases[(b)]	**23,084**	26,502
Deferred debt service adder[(k)]	**86,082**	76,334
Asset retirement obligations – Nuclear[(l)]	**11,766**	8,316
Other regulatory liabilities[(m)]	**18,445**	3,708
Total Regulatory Liabilities	**197,748**	166,967
Net regulatory assets	**$ 347,639**	$ 363,287

(a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt that are being amortized over the lives of the refunding debt, which range up to 27 years.

(b) Represents the difference between expense recognized for rate-making purposes and financial statement purposes related to capital lease payments and the aggregate of the amortization of the asset and interest on the obligation.

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

(d) Represents losses on settled interest rate swap arrangements that are being amortized through the end of 2018.

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

(f) Deferred charges related to Vogtle Units No. 3 and No. 4 training and interest related carrying costs of such training. Amortization will commence effective with the commercial operation date of each unit and amortized to expense over the life of the units.

(g) Deferral of net loss associated with the change in fair value and expired cost of interest rate options purchased to hedge interest rates on certain borrowings related to Vogtle Units No.3 and No.4 construction. Amortization will commence in February 2020 and will be amortized through February 2044, the life of the DOE-guaranteed loan which is financing a portion of the construction project.

(h) Effects on net margin for Smith and Hawk Road Energy Facilities were deferred through the end of 2015 and are being amortized over the remaining life of each respective plant.

(i) Represents the accrual of retirement costs associated with long-lived assets for which there are no legal obligations to retire the assets.

(j) Represents collections for future major maintenance costs; revenues are recognized as major maintenance costs are incurred.

(k) Represents collections to fund certain debt payments to be made through the end of 2025 which will be in excess of amounts collected through depreciation expense; the deferred credits will be amortized over the remaining useful life of the plants.

(l) Represents difference in timing of recognition of the costs of decommissioning and ashpond remediation for financial statement purposes and for ratemaking purposes.

(m) The amortization periods for other regulatory assets range up to 33 years and the amortization periods of other regulatory liabilities range up to 10 years.

s. Related parties

We and our 38 members are members of Georgia Transmission. Georgia Transmission provides transmission services to its members for delivery of its members' power purchases from us and other power suppliers. We have entered into an agreement with Georgia Transmission to provide transmission services for third party transactions and for service to our own facilities. For 2016, 2015, and 2014, we incurred expenses from Georgia Transmission of $27,399,000, $28,172,000, and $27,893,000, respectively.

We, Georgia Transmission and 38 of our members are members of Georgia Systems Operations. Georgia Systems Operations operates the system control center and currently provides us system operations services and administrative support services. For 2016, 2015, and 2014, we incurred expenses from Georgia Systems Operations of $23,994,000, $22,616,000, and $23,351,000, respectively.

t. Other income

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

	(dollars in thousands)		
	2016	2015	2014
Capital credits from associated companies (Note 4)	**$ 1,679**	$ 1,859	$ 1,986
Net revenue from Georgia Transmission and Georgia System Operations for shared Administrative and General costs	**6,553**	6,278	4,944
Miscellaneous other	**(5,561)**	1,006	(310)
Total	**$ 2,671**	$ 9,143	$ 6,620

u. New accounting pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued "Revenue from Contracts with Customers" (Topic 606). The new revenue standard requires that an entity recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The standard was effective for the annual reporting period beginning after December 15, 2016 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes additional footnote disclosures). Early adoption was not permitted.

In August 2015, the FASB issued an update to Topic 606 deferring the effective date by one year. The standard is effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. The standard also permits early adoption of the standard, but not before the original effective date of December 15, 2016.

While we expect that the majority of our revenues will be included in the scope of Topic 606, we have not fully completed our evaluation of the new revenue standard. Our evaluation process includes, but is not limited to, identifying contracts within the scope of Topic 606, reviewing and documenting our accounting for these contracts and assessing the applicability of the variable consideration guidance. A large majority of our revenues is derived from substantially identical wholesale power contracts that we have with each of our 38 members. We expect the pattern of revenue recognition pursuant to our wholesale power contracts will remain unchanged on an annual basis under the new revenue standard. However, we continue to evaluate the effects, if any, of Topic 606 on our interim period revenues as it relates to budget adjustments, which may be made during the year that affect our annual revenue requirement. We also continue to evaluate other revenue streams and the related contracts, as well as monitor issues specific to the power and utilities industry. As the ultimate impact of the new revenue standard has not yet been determined, we have not elected our transition method.

In July 2015, the FASB issued ‘‘Inventory (Topic 330): Simplifying the Measurement of Inventory.’’ Under the new inventory standard, inventories are required to be measured at the lower of cost and net realizable value, the latter representing the estimated selling price in the ordinary course of business, reduced by costs of completion, disposal, and transportation. Under current guidance, inventories are required to be measured at the lower of cost or market, but depending upon specific circumstances, market could be replacement cost, net realizable value, or net realizable value reduced by a normal profit margin. The amendments do not apply to inventory measured using the last-in, first-out or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first out or average cost, the method used to measure all of our inventories. The new standard is effective for us prospectively for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted as of the beginning of an interim or annual reporting period. As permitted, on April 1, 2016, we early adopted these amendments and applied their provisions prospectively. The adoption of this amendment did not have a material impact on our consolidated financial statements.

In November 2015, the FASB issued ‘‘Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes.’’ The amendments in this standard simplifies the presentation of deferred income taxes by eliminating the separate classification of deferred income tax assets and liabilities into current and noncurrent amounts in the statement of financial position. The amendments in the update require that all deferred tax assets and liabilities be classified as noncurrent in the consolidated balance sheets. The new standard is effective for us either prospectively or retrospectively for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted as of the beginning of an interim or annual reporting period. As permitted, on October 1, 2016, we early adopted these amendments and applied their provisions retrospectively. There was no impact to our consolidated financial statements as a result of the adoption of this standard.

In January 2016, the FASB issued ‘‘Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities.’’ The amendments in this update address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. The new standard is effective for us for annual reporting periods beginning after December 15, 2017, and interim periods therein. Certain provisions within this update can be adopted early. Certain provisions within this update should be applied by means of a cumulative effect adjustment to the balance sheets of the fiscal year of adoption and certain provisions should be applied prospectively. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In February 2016, the FASB issued "Leases (Topic 842)." The new leases standard requires a dual approach for lessee accounting under which a lessee would account for leases as finance leases or operating leases. Both finance leases and operating leases will result in the lessee recognizing a right-of-use (ROU) asset and a corresponding lease liability. For finance leases the lessee would recognize interest expense and amortization of the ROU asset and for operating leases the lessee would recognize a straight-line total lease expense. The new lease standard does not substantially change lessor accounting. The new leases standard is effective for us on a modified retrospective approach for annual reporting periods beginning after December 15, 2018, and interim periods therein. Early adoption is permitted. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In June 2016, the FASB issued "Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." The amendments in this update replace the current incurred loss impairment methodology with a methodology that reflects expected credit losses. The new standard is effective for us prospectively for annual reporting periods beginning after December 15, 2019, and interim periods therein. The amendments in this update can be adopted earlier as of the fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In August 2016, the FASB issued "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." The amendments in this standard provide specific guidance on eight cash flow classification issues relating to how certain cash receipts and cash payments are presented and classified in the statement of cash flows, thereby reducing the current and potential future diversity in practice. The new standard is effective for us for annual reporting periods beginning after December 15, 2017, and interim periods therein. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. The amendments should be applied using a retrospective transition method to each period presented. If it is impracticable to apply the amendments retrospectively for some of the issues, the amendments for those issues would be applied prospectively as of the earliest date practicable. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In November 2016, the FASB issued "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)." The amendments in this standard require the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are to be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period amounts shown on the statement of cash flows. The new standard is effective for us on a retrospective basis for annual reporting periods beginning after December 15, 2017, and interim periods therein. Early adoption is permitted, including adoption in an interim period. Our restricted cash balances are nominal and accordingly we do not expect the adoption of this standard to have a material impact on our consolidated financial statements.

2. Fair Value:

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

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

- *Level 1.* Quoted prices from active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Quoted prices in active markets provide the most reliable evidence of fair value and are used to measure fair value whenever available. Level 1 primarily consists of financial instruments that are exchange-traded.

- *Level 2.* Pricing inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 2 primarily consists of financial instruments that are non-exchange-traded but have significant observable inputs.
- *Level 3.* Pricing inputs that include significant inputs which are generally less observable from objective sources. These inputs may include internally developed methodologies that result in management's best estimate of fair value. Level 3 financial instruments are those whose fair value is based on significant unobservable inputs.

Assets and liabilities measured at fair value are based on one or more of the following three valuation techniques:

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

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

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

	Fair Value Measurements at Reporting Date Using			
	December 31, 2016	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(dollars in thousands)			
Nuclear decommissioning trust funds:				
Domestic equity	**$ 170,408**	$ 170,408	$ –	$ –
International equity trust	**66,861**	–	66,861	–
Corporate bonds	**60,019**	–	60,019	–
US Treasury and government agency securities	**65,725**	65,725	–	–
Agency mortgage and asset backed securities	**17,410**	–	17,410	–
Municipal Bonds	**943**	–	943	–
Other	**4,663**	4,663	–	–
Long-term investments:				
Corporate bonds	**11,853**	–	11,853	–
US Treasury and government agency securities	**12,187**	12,187	–	–
Agency mortgage and asset backed securities	**1,651**	–	1,651	–
International equity trust	**15,946**	–	15,946	–
Mutual funds	**57,932**	57,932	–	–
Other	**305**	305	–	–
Natural gas swaps	**(15,090)**	–	(15,090)	–

	Fair Value Measurements at Reporting Date Using			
	December 31, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(dollars in thousands)			
Nuclear decommissioning trust funds:				
Domestic equity	$ 151,178	$ 151,178	$ –	$ –
International equity trust	68,753	–	68,753	–
Corporate bonds	48,450	–	48,450	–
US Treasury and government agency securities	75,173	74,698	475	–
Agency mortgage and asset backed securities	15,503	–	15,503	–
Other	4,772	4,772	–	–
Long-term investments:				
Corporate bonds	9,903	–	9,903	–
US Treasury and government agency securities	13,772	13,772	–	–
Agency mortgage and asset backed securities	1,121	–	1,121	–
International equity trust	12,846	–	12,846	–
Mutual funds	48,649	48,649	–	–
Other	479	479	–	–
Interest rate options	1,010	–	–	1,010(1)
Natural gas swaps	24,995	–	24,995	–

(1) Interest rate options as reflected on the Consolidated Balance Sheet include the fair value of the interest rate options.

The Level 2 investments above in corporate bonds and agency mortgage and asset backed securities may not be exchange traded. The fair value measurements for these investments are based on a market approach, including the use of observable inputs. Common inputs include reported trades and broker/dealer bid/ask prices. The fair value of the Level 2 investments above in international equity trust are calculated based on the net asset value per share of the fund. There are no unfunded commitments for the international equity trust and redemption may occur daily with a three-day redemption notice period.

The following tables present the changes in Level 3 assets measured at fair value on a recurring basis during the years ended 2016 and 2015, respectively.

	Year Ended December 31, 2016
	Interest rate options
	(dollars in thousands)
Assets:	
Balance at December 31, 2015	$ 1,010
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(1,010)
Balance at December 31, 2016	**$ –**

	Year Ended December 31, 2015
	Interest rate options
	(dollars in thousands)
Assets:	
Balance at December 31, 2014	$ 4,371
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(3,361)
Balance at December 31, 2015	$ 1,010

We estimate the value of the interest rate options as the sum of time value and any intrinsic value minus a counterparty credit adjustment. Intrinsic value is the value of the underlying swap, which we are able to calculate based on the forward LIBOR swap rates, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, all of which we are able to effectively observe. Time value is the additional value of the swaption due to the fact that it is an option. We estimate the time value using an option pricing model which, in addition to the factors used to calculate intrinsic value, also takes into account option volatility, which we estimate based on option valuations we obtain from various sources. We estimate the counterparty credit adjustment by observing credit attributes, including the credit default swap spread of entities similar to the counterparty and the amount of credit support that is available for each swaption. Since the primary component of the LIBOR swaptions' value is time value, which is based on estimated option volatility derived from valuations of comparable instruments that are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We believe the estimated fair values for the LIBOR swaptions we hold are based on the most accurate information available for these types of derivative contracts. For additional information regarding our interest rate options, see Note 3.

The estimated fair values of our long-term debt, including current maturities at December 31, 2016 and 2015 were as follows (in thousands):

	2016		2015	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 8,304,523**	**$ 9,043,029**	$ 7,575,027	$ 8,445,630

The estimated fair value of long-term debt is classified as Level 2 and is estimated based on observed or quoted market prices for the same or similar issues or on current rates offered to us for debt of similar maturities. The primary sources of our long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank that is guaranteed by the Rural Utilities Service or the U.S. Department of Energy. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC) and by CoBank, ACB. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from a third party data reporting service, and are based on secondary market trading of our debt. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of December 31, 2016 and 2015 plus an applicable spread, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank. The rates on the CFC debt are fixed and the valuation is based on rate quotes provided by CFC. We use an interest rate quote sheet provided by CoBank for valuation of the CoBank debt, which reflects current rates for similar loans.

For cash and cash equivalents, restricted cash and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments. As discussed in Note 1n, restricted cash and investments primarily consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. The carrying amount approximates fair value because of the liquid nature of the deposits with the U.S. Treasury.

3. Derivative instruments:

Our risk management and compliance committee provides general oversight over all risk management and compliance activities, including but not limited to, commodity trading, investment portfolio management and interest rate risk management. We use commodity trading derivatives to manage our exposure to fluctuations in the market price of natural gas. To hedge the risk of rising interest rates on a portion of our anticipated long-term debt to be incurred in connection with capital expenditures, we have entered into interest rate options. We do not apply hedge accounting for any of these derivatives, but apply regulatory accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps and interest rate options are reflected as regulatory assets or liabilities, as appropriate.

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 have established policies and procedures to manage credit risk through counterparty analysis, exposure calculation and monitoring, exposure limits, collateralization and certain other contractual provisions.

It is possible that volatility in commodity prices and/or interest rates could cause us to have credit risk exposures with one or more counterparties. We currently have credit risk exposure to our interest rate options counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of December 31, 2016, all of the counterparties with transaction amounts outstanding under our hedging programs are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

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

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

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

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

At December 31, 2016 and 2015, the estimated fair value of our natural gas contracts were a net asset of $15,090,000 and a net liability of $22,848,000, respectively.

As of December 31, 2016 and 2015, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2016 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit of approximately $62,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of December 31, 2016 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2017	23.2
2018	20.4
2019	13.5
2020	9.0
2021	2.5
Total	**68.6**

Interest rate options. We are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4. In fourth quarter of 2011, we purchased seventeen LIBOR swaptions at a cost of $100,000,000 with a total notional amount of approximately $2,200,000,000 to hedge the interest rates on a portion of the debt that we are incurring to finance the two additional nuclear units at Plant Vogtle. Since inception, sixteen of these swaptions having a notional amount of approximately $2,099,035,000 have expired and, as of December 31, 2016, the notional amount of our remaining swaption, which expires March 31, 2017, was approximately $80,169,000.

The LIBOR swaptions were designed to cap our effective interest rate at a specified fixed interest rate on a specified option expiration date. This is accomplished by means of a payment of the cash settlement value our counterparties are obligated to make to us if prevailing fixed LIBOR swap rates exceed the specified fixed rate on the option expiration date. This payment would partially offset our interest costs, thereby reducing our effective interest rate. The cash settlement value is calculated based on the value of an underlying swap which we have the right, but not the obligation, to enter into, which would begin on the option expiration date and extend until 2042 and under which we would pay the specified fixed rate and receive a floating LIBOR rate. The cash settlement value would be zero if the swaption is out-of-the-money (that is, if the specified fixed rate is at or above then-current swap rates) on the expiration date. The fixed rate on the unexpired swaption we hold is 3.88%, which is 139 basis points above the corresponding LIBOR swap rate in effect as of December 31, 2016. Swaptions having notional amounts totaling $310,533,000 expired without value during the year ended December 31, 2016. The remaining swaption will expire March 31, 2017.

We paid all the premiums to purchase these LIBOR swaptions at the time we entered into these transactions. At December 31, 2016 and 2015, the fair value of these swaptions was approximately $0 and $1,010,000, respectively. To manage our credit exposure to our counterparties, we negotiated credit support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the swaptions outstanding for that counterparty exceeds a certain threshold. The collateral thresholds can range from $0 to $10,000,000 depending on each counterparty's credit rating. As of December 31, 2016 and 2015, there were no collateral postings required of the counterparties.

We are deferring realized and unrealized gains or losses from the change in fair value of each LIBOR swaption as well as related carrying and other incidental costs in accordance with our rate-making treatment. The deferral will continue until February 2020, at which time the deferred costs from the settlement of the interest rate options will be amortized and collected in rates over the life of the $2,200,000,000 of debt that we hedged with the swaptions.

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at December 31, 2016 and 2015.

	Balance Sheet Location	Fair Value 2016	Fair Value 2015
		(dollars in thousands)	
Not designated as hedges:			
Assets			
Interest rate options	Other deferred charges	**$ –**	$ 1,010
Natural gas swaps	Other current assets	**$ 13,833**	–
Natural gas swaps	Other deferred charges	**$ 3,289**	–
Liabilities			
Natural gas swaps	Other current liabilities	**$ 54**	$ 22,848
Natural gas swaps	Other deferred credits	**$ 1,977**	$ –

The following table presents the realized gains and (losses) on derivative instruments recognized in margin for the year ended December 31, 2016, 2015 and 2014.

	Consolidated Statement of Revenues and Expenses Location	2016	2015	2014
		(dollars in thousands)		
Not designated as hedges:				
Natural Gas Swaps	Fuel	**$ 2,445**	$ 206	$ 1,881
Natural Gas Swaps	Fuel	**(19,697)**	(20,102)	(1,033)
		$ (17,252)	$ (19,896)	$ 848

The following table presents the unrealized gains and (losses) on derivative instruments deferred on the balance sheet at December 31, 2016 and 2015.

	Consolidated Balance Sheet Location	2016	2015
Not designated as hedges:			
Natural Gas Swaps	Regulatory asset	**$ (62)**	$ (22,848)
Natural Gas Swaps	Regulatory liability	**15,152**	
Interest Rate Options	Regulatory asset	**(5,788)**	(25,915)
Total not designated as hedges		**$ 9,302**	$ (48,763)

The following table presents the gross amounts of derivatives and their related offset amounts as permitted by their respective master netting agreements and obligations to return cash collateral at December 31, 2016 and 2015.

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts offset on the Balance Sheet	Cash Collateral	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
	(dollars in thousands)			
December 31, 2016				
Natural gas swaps	$ 15,090	$ –	$ –	$ 15,090
Natural gas swaps	$ (15,090)	$ –	$ –	$ (15,090)
Interest rate options	$ 5,788	$ (5,788)	$ –	$ –
December 31, 2015				
Assets:				
Natural gas swaps	$ (22,848)	$ –	$ –	$ (22,848)
Interest rate options	$ 26,925	$ (25,915)	$ –	$ 1,010

4. Investments:

Investments in debt and equity securities

Investment securities we hold are classified as available-for-sale. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from patronage capital, except that, in accordance with our rate-making treatment, realized and unrealized gains and losses from investment securities held in the nuclear decommissioning funds are directly added to or deducted from the regulatory asset or liability for asset retirement obligations. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 65% of these gross unrealized losses were in effect for less than one year.

		(dollars in thousands)		
		Gross Unrealized		
2016	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 237,317**	**$ 51,054**	**$ (5,041)**	**$ 283,330**
Debt	**201,492**	**1,167**	**(3,423)**	**199,236**
Other	**3,339**	**–**	**(2)**	**3,337**
Total	**$ 442,148**	**$ 52,221**	**$ (8,466)**	**$ 485,903**

		(dollars in thousands)		
		Gross Unrealized		
2015	Cost	Gains	Losses	Fair Value
Equity	$ 230,123	$ 37,494	$ (9,635)	$ 257,982
Debt	189,700	1,158	(3,491)	187,367
Other	5,255	–	(4)	5,251
Total	$ 425,078	$ 38,652	$ (13,130)	$ 450,600

All of the available-for-sale investments are recorded at fair value 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, 2016 and 2015 are as follows:

	(dollars in thousands)			
	2016		2015	
	Cost	**Fair Value**	Cost	Fair Value
Due within one year	**$ 8,292**	**$ 8,268**	$ 8,559	$ 8,612
Due after one year through five years	**52,452**	**52,054**	50,018	49,538
Due after five years through ten years	**65,657**	**64,971**	56,448	55,880
Due after ten years	**75,091**	**73,943**	74,675	73,337
Total	**$ 201,492**	**$ 199,236**	$ 189,700	$ 187,367

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2016, 2015 and 2014:

	(dollars in thousands)		
	2016	2015	2014
Gross realized gains	**$ 19,934**	$ 53,453	$ 64,437
Gross realized losses	**(20,030)**	(18,989)	(46,258)
Proceeds from sales	**439,540**	640,217	438,941

Investment in associated companies

Investments in associated companies were as follows at December 31, 2016 and 2015:

	(dollars in thousands)	
	2016	2015
National Rural Utilities Cooperative Finance Corporation (CFC)	**$ 24,049**	$ 24,040
CT Parts, LLC	**10,250**	11,067
Georgia Transmission Corporation	**27,285**	25,872
Georgia System Operations Corporation	**7,500**	7,200
Other	**3,699**	3,831
Total	**$ 72,783**	$ 72,010

The CFC investments consist of capital term certificates required in connection with our membership in CFC and a voluntary investment in CFC member capital securities. Accordingly, there is no market for these investments. The investment in Georgia Transmission represents capital credits. The investment in Georgia System Operations represents loan advances. Repayments of these advances are due by December 2020.

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

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 Rocky Mountain. In each transaction, we leased a portion of our undivided interest in Rocky Mountain to six separate owner trusts 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. Immediately thereafter, the owner trusts leased their undivided interests in Rocky Mountain to our wholly owned subsidiary, Rocky Mountain Leasing Corporation, or RMLC, for a term of 30 years under six separate leases. RMLC then subleased the undivided interests back to us under six separate leases for an identical term.

In 2012, we terminated five of the six lease transactions prior to the end of their lease terms. The remaining lease in place represented approximately 10% of the original lease transactions. We have a guarantee for the basic rental payments under the remaining lease. The fair value amount relating to the guarantee of basic rent payments is immaterial to us principally due to the high credit rating of the payment undertaker. The basic rental payments remaining through the end of the lease are approximately $53,545,000.

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

5. Income taxes:

While we are a not-for-profit membership corporation formed under the laws of Georgia, we are subject to federal and state income taxation. As a taxable cooperative, we are allowed to deduct patronage dividends that we allocate to our members for purposes of calculating our taxable income. We annually allocate income and deductions between patronage and non-patronage activities and substantially all of our income is from patronage-sourced activities, resulting in no current period income tax expense or current or deferred income tax liability.

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

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

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

	2016	2015	2014
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Patronage exclusion	**(34.7%)**	(34.7%)	(34.4%)
Other	**(0.3%)**	(0.3%)	(0.6%)
Effective income tax rate	**0.0%**	0.0%	0.0%

The components of our net deferred tax assets and liabilities as of December 31, 2016 and 2015 were as follows:

	(dollars in thousands)	
	2016	2015
Deferred tax assets		
Net operating losses	**$ 29,724**	$ 29,724
Tax credits (alternative minimum tax and other)	**599**	1,198
Accounting for Rocky Mountain transactions	**349,127**	348,779
Other assets	**109,793**	107,527
Deferred tax assets	**489,243**	487,228
Less: Valuation allowance	**(29,724)**	(29,724)
Net deferred tax assets	**$ 459,519**	$ 457,504
Deferred tax liabilities		
Depreciation	**$ 435,570**	$ 426,173
Accounting for Rocky Mountain transactions	**170,402**	167,907
Other liabilities	**123,121**	131,454
Deferred tax liabilities	**729,093**	725,534
Net deferred tax liabilities	**269,574**	268,030
Less: Patronage exclusion	**(269,574)**	(268,030)
Net deferred taxes	**$ –**	$ –

As of December 31, 2016, we have federal tax net operating loss carryforwards and alternative minimum tax credits as follows:

	(dollars in thousands)	
Expiration Date	Alternative Minimum Tax Credits	NOLs
2018	$ –	$ 61,533
2019	–	10,516
2020	$ –	4,362
None	$ 599	$ –
	$ 599	$ 76,411

The net operating loss expiration dates start in the year 2018 and end in the year 2020. Due to the tax basis method for allocating patronage and as shown by the above valuation allowance, it is not more likely than not that the deferred tax asset related to the net operating losses will be realized.

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. The PATH Act allows us to accelerate and monetize AMT credits in lieu of bonus depreciation up through 2019. We intend to make this election when filing our tax returns for tax years ended December 31, 2016 and December 31, 2017. We also expect to fully monetize the remaining balance of tax credits of $599,000 on the 2017 tax return.

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

We file a U.S. federal consolidated income tax return. The U.S. federal statute of limitations remains open for the year 2013 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 2013 forward. We have no liabilities recorded for uncertain tax positions.

6. 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 terms of the leases. Three of the leases have lease terms through December 31, 2027, and one lease extends through June 30, 2031. The assumed interest rate at inception of the lease in 1985 was 11.05%.

The minimum lease payments under the capital leases together with the present value of the net minimum lease payments as of December 31, 2016 are as follows:

Year Ending December 31,	(dollars in thousands)
2017	$ 22,424
2018	14,949
2019	14,949
2020	14,949
2021	14,949
2022-2031	100,380
Total minimum lease payments	182,600
Less: Amount representing interest	(84,069)
Present value of net minimum lease payments	98,531
Less: Current portion	(6,435)
Long-term balance	$ 92,096

The Scherer No. 2 lease is reported as a capital lease. 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. Capital lease amortization is recorded in depreciation and amortization expense.

7. Debt:

Long-term debt consists of first mortgage notes payable to the United States of America acting through the Federal Financing Bank (FFB) and guaranteed by the Rural Utilities Service or the U.S. Department of Energy, first mortgage bonds payable (FMBs), first mortgage notes issued in conjunction with the sale by public authorities of pollution control revenue bonds (PCBs) and first mortgage notes payable to CoBank and CFC. Substantially all of our owned tangible and certain of our intangible assets are pledged under our first mortgage indenture as collateral for the Federal Financing Bank notes, the first mortgage bonds, the first mortgage notes issued in conjunction with the sale of pollution control revenue bonds, and the CoBank and CFC first mortgage notes.

Maturities for long-term debt and capital lease obligations through 2021 are as follows:

	(dollars in thousands) 2017	2018	2019	2020	2021
FFB	$ 183,259	$ 151,297	$ 156,376	$ 171,441	$ 176,620
FMBs	1,010	1,010	351,010	1,010	1,010
PCBs[1]	122,620	56,028	37,352	188,226	36,000
CFC	937	984	1,035	391	–
CoBank	2,600	–	–	–	–
	310,426	209,319	545,773	361,068	213,630
Capital Leases	6,435	4,905	5,462	6,082	6,772
Total	$ 316,861	$ 214,224	$ 551,235	$ 367,150	$ 220,402

(1) In addition to regularly scheduled principal payments on the bonds, this includes amounts that would be due if the standby letters of credit supporting the Series 2009 and Series 2010 bonds were drawn upon and became payable in accordance with their terms, such as would occur if the credit facility the letters of credit were issued under was not renewed or extended at its expiration date. These amounts equal $56 million in 2018, $37 million in 2019 and $152 million in 2020. We anticipate extending these credit facilities before their expiration. The nominal maturities of the Series 2009 and Series 2010 pollution control bonds range from 2030 through 2038.

The weighted average interest rate on our long-term debt at December 31, 2016 and 2015 was 4.34% and 4.45%, respectively.

Long-term debt outstanding and the associated unamortized debt issuance costs and debt discounts at December 31, 2016 and 2015 are as follows:

	2016		2015	
	Principal	**Unamortized Debt Issuance Costs and Debt Discounts**	Principal	Unamortized Debt Issuance Costs and Debt Discounts
		(dollars in thousands)		
FFB	**$ 4,259,723**	**$ 55,754**	$ 3,777,540	$ 56,851
FMBs	**3,058,083**	**36,717**	2,809,093	32,002
PCBs	**980,770**	**8,789**	980,770	9,135
CFC	**3,347**	**–**	4,238	–
CoBank	**2,600**	**–**	3,386	–
	$ 8,304,523	**$ 101,260**	$ 7,575,027	$ 97,988

We use the effective interest rate method to amortize debt issuance costs and debt discounts as well as the straight-line method when the results approximate those of the effective interest rate method. Unamortized debt issuance costs and debt discounts are being amortized to expense over the life of the respective debt issues.

a) *Department of Energy Loan Guarantee:*

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (the "Title XVII Loan Guarantee Program"), we and the U.S. Department of Energy, acting by and through the Secretary of Energy, entered into a Loan Guarantee Agreement on February 20, 2014 pursuant to which the Department of Energy agreed to guarantee our obligations under the Note Purchase Agreement dated as of February 20, 2014 (the "Note Purchase Agreement"), among us, the FFB and the Department of Energy and two future advance promissory notes, each dated February 20, 2014, made by us to the FFB (the "FFB Notes" and together with the Note Purchase Agreement, the "FFB Credit Facility Documents"). The FFB Credit Facility Documents provide for a multi-advance term loan facility (the "Facility"), under which we may make long-term loan borrowings through the FFB.

Proceeds of advances made under the Facility will be used to reimburse us for a portion of certain costs of construction relating to Vogtle Units No. 3 and No. 4 that are eligible for financing under the Title XVII Loan Guarantee Program. Aggregate borrowings under the Facility may not exceed $3,057,069,461, of which $335,471,604 is designated for capitalized interest.

Under the Loan Guarantee Agreement, we are obligated to reimburse the Department of Energy in the event the Department of Energy is required to make any payments to the FFB under the guarantee. Our payment obligations to FFB under the FFB Notes and reimbursement obligations to the Department of Energy under its guarantee are secured equally and ratably with all of our other notes and obligations issued under our first mortgage indenture. The final maturity date for each advance is February 20, 2044. Interest is payable quarterly in arrears and principal payments will begin on February 20, 2020. Under both FFB Notes, the interest rates during the applicable interest rate periods will equal the current average yield on U.S. Treasuries of comparable maturity at the beginning of the interest rate period, plus a spread equal to 0.375%.

During 2016, we received advances under the Facility totaling $450,000,000. At December 31, 2016, aggregate DOE-guaranteed borrowings totaled $1,678,442,000, including capitalized interest. Advances may be requested under the Facility on a quarterly basis through December 31, 2020. Future advances are subject to satisfaction of customary conditions, including certification of compliance with the requirements of the Title XVII Loan Guarantee Program, accuracy of project-related representations and warranties, delivery of updated project-related information, our continued ownership of our interest in Vogtle Units No. 3 and No. 4 free and clear of any liens except those permitted under the Loan Guarantee Agreement, evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act, as amended, and certification from the Department of Energy's consulting engineer that proceeds of the advance are used to reimburse eligible project costs. The failure by the Contractor to perform its obligations under the EPC Agreement could affect our ability to satisfy the conditions required to receive future advances.

Under the Loan Guarantee Agreement, we are subject to customary borrower affirmative and negative covenants and events of default. In addition, we are subject to project-related reporting requirements and other project-specific covenants and events of default.

If certain events occur, the Department of Energy may, at its option, (i) elect to suspend or terminate the FFB's commitment to make further advances under the Facility, and may later revoke any such suspension, or (ii) require us to repay the outstanding principal amount of all borrowings under the Facility over a period of five years, with level principal amortization. These events include (i) cessation of the construction of Vogtle Units No. 3 and No. 4 for twelve consecutive months, (ii) termination of the EPC Agreement under certain circumstances, (iii) loss of or failure to receive necessary regulatory approvals under certain circumstances, (iv) loss of access to intellectual property rights necessary to construct or operate Vogtle Units No. 3 and No. 4 under certain circumstances, (v) our failure to fund our share of operation and maintenance expenses for Vogtle Units No. 3 and No. 4 for twelve consecutive months, (vi) change of control of Oglethorpe and (vii) certain events of loss or condemnation. If we receive proceeds from an event of condemnation relating to Vogtle Units No. 3 and No. 4, such proceeds must be applied to immediately prepay outstanding borrowings under the Facility. We may also voluntarily prepay outstanding borrowings under the Facility. Under the FFB Credit Facility Documents, any prepayment will be subject to a make-whole premium or discount, as applicable.

Upon notice to the Department of Energy from the Co-owners of their intent to terminate the EPC Agreement for convenience, the Department of Energy may elect to continue construction of Vogtle Units No. 3 and No. 4. In such an event, unless we elect to join the Department of Energy in continuing construction, the Department of Energy will have the right, subject to certain conditions including obtaining necessary NRC approvals, to assume our rights and obligations under the principal agreements relating to Vogtle Units No. 3 and No. 4 and to acquire all or a portion of our ownership interest in Vogtle Units No. 3 and No. 4.

b) *Rural Utilities Service Guaranteed Loans:*

During 2016, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $94,460,000 for long-term financing of general and environmental improvements at existing plants.

In January 2017, we received an additional $4,517,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

c) *Pollution Control Revenue Bonds:*

In January 2017, we refinanced $122,600,000 of variable rate pollution control revenue bonds with original maturity dates ranging from 2020 through 2040, through the issuance of commercial paper. The bonds were classified as current debt at December 31, 2016.

d) *Credit Facilities:*

As of December 31, 2016, we had a total of $1,610,000,000 of committed credit arrangements comprised of four separate facilities with maturity dates that range from October 2018 to March 2020. These credit facilities are for general working capital purposes, issuing letters of credit and backing up outstanding commercial paper. Under our unsecured committed lines of credit that we had in place at December 31, 2016, we had the ability to issue letters of credit totaling $760,000,000 in the aggregate, of which $509,000,000 remained available. At December 31, 2016, we had 1) $251,000,000 under these lines of credit in the form of issued letters of credit supporting variable rate demand bonds and collateral postings to third parties, and 2) $102,000,000 dedicated under one of these lines of credit to support a like amount of commercial paper that was outstanding.

The weighted average interest rate on short-term borrowings at December 31, 2016 and December 31, 2015 was 0.93% and 0.43%, respectively.

8. 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 electric generating plants. Each co-owner is responsible for providing their own financing. The plant investments disclosed in the table below represent our undivided interest in each plant. A summary of our plant investments and related accumulated depreciation as of December 31, 2016 and 2015 is as follows:

Plant	2016 Investment	2016 Accumulated Depreciation	2015 Investment	2015 Accumulated Depreciation
	(dollars in thousands)			
In-service[1]				
Owned property				
Vogtle Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**$ 2,885,559**	**$ (1,712,642)**	$ 2,869,142	$ (1,674,431)
Vogtle Units No. 3 & No. 4 *(Nuclear – 30% ownership)*	**36,163**	**(1,567)**	22,557	(891)
Hatch Units No. 1 & No. 2 *(Nuclear – 30% ownership)*	**809,971**	**(407,400)**	767,019	(391,822)
Wansley Units No. 1 & No. 2 *(Fossil – 30% ownership)*	**577,781**	**(190,974)**	499,180	(163,266)
Scherer Unit No. 1 *(Fossil – 60% ownership)*	**1,083,772**	**(368,948)**	1,086,435	(332,493)
Doyle *(Combustion Turbine – 100% leasehold)*[2]	**135,849**	**(102,642)**	124,051	(90,590)
Rocky Mountain Units No. 1, No. 2 & No. 3 *(Hydro – 75% ownership)*	**607,742**	**(234,765)**	600,640	(222,888)
Hartwell *(Combustion Turbine – 100% ownership)*	**227,878**	**(104,342)**	226,737	(103,111)
Hawk Road *(Combustion Turbine – 100% ownership)*	**250,595**	**(69,984)**	243,517	(70,832)
Talbot *(Combustion Turbine – 100% ownership)*	**290,790**	**(119,874)**	290,463	(111,617)
Chattahoochee *(Combined cycle – 100% ownership)*	**313,693**	**(123,946)**	310,788	(114,914)
Smith *(Combined cycle – 100% ownership)*	**614,453**	**(176,701)**	601,903	(166,324)
Wansley *(Combustion Turbine – 30% ownership)*	**3,582**	**(3,569)**	3,582	(3,513)
Transmission plant	**92,085**	**(53,251)**	90,195	(50,786)
Other	**99,644**	**(61,356)**	116,396	(73,442)
Property under capital lease:				
Scherer Unit No. 2 *(Fossil – 60% leasehold)*	**757,282**	**(383,378)**	743,543	(354,918)
Total in-service	**$ 8,786,839**	**$ (4,115,339)**	$ 8,596,148	$ (3,925,838)
Construction work in progress				
Vogtle Units No. 3 & No. 4	**$ 3,069,476**		$ 2,724,543	
Environmental and other generation improvements	**158,181**		143,723	
Other	**557**		403	
Total construction work in progress	**$ 3,228,214**		$ 2,868,669	

(1) Amounts include plant acquisition adjustments at December 31, 2016 and 2015 of $197,000,000.
(2) On August 20, 2015, we acquired Doyle which we previously operated under a capital lease.

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) on the accompanying Statement of Revenues and Expenses.

b. Construction

We, Georgia Power, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Our binding ownership interest and proportionate share of the cost to construct these units is 30%. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company as its agent for licensing, engineering, procurement, contract management, construction and pre-operation services.

In 2008, Georgia Power, acting for itself and as agent for the Co-owners, entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, the Contractor). Stone & Webster was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. Pursuant to the EPC Agreement, the Contractor agreed to design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle.

Under the EPC Agreement, the Co-owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders and performance bonuses. The EPC Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to a cap of 10% of the contract price, or approximately $920,000,000 to $930,000,000. In addition, the EPC Agreement provides for limited cost sharing by the Co-owners for increases to Contractor costs under certain conditions. The maximum amount of additional capital costs under this provision attributable to us is $75,000,000. Each Co-owner is severally, not jointly, liable to the Contractor for its proportionate share, based on ownership interest, of all amounts owed under the EPC Agreement. In the event of certain credit rating downgrades of any Co-owner, such Co-owner will be required to provide a letter of credit or other credit enhancement.

Under the terms of the EPC Agreement, the Contractor does not have the right to terminate the EPC Agreement for convenience. The Contractor may terminate the EPC Agreement under certain circumstances, including certain suspension or delays of work by the Co-owners, action by a governmental authority to stop work permanently, certain breaches of the EPC Agreement by the Co-owners, Co-owner insolvency, and certain other events. In the event of an abandonment of work by the Contractor, the maximum liability of the Contractor under the EPC Agreement is increased significantly but remains subject to limitations. The EPC Agreement permits Georgia Power, acting for itself and as agent for the Co-owners, to terminate the EPC Agreement at any time for their convenience, provided that the Co-owners will be required to pay certain termination costs.

Certain obligations of Westinghouse under the EPC Agreement, including, but not limited to, liquidated damages and damages related to abandoning the Vogtle project, have been guaranteed by Toshiba Corporation, Westinghouse's parent company. In January 2016, as a result of credit rating downgrades of Toshiba, Westinghouse provided the Co-owners with $920,000,000 of letters of credit pursuant to the terms of the EPC Agreement. These letters of credit remain in place in accordance with the terms of the EPC Agreement.

On February 14, 2017, Toshiba announced preliminary earnings results for the period ended December 31, 2016, which included a goodwill impairment charge of over $6,000,000,000 at Westinghouse primarily attributable to the increased cost estimates to complete its nuclear projects in the United States, including Vogtle Units No. 3 and No. 4. As a result of the charge, Toshiba warned that it will likely be in a negative equity position which has created significant uncertainty regarding potential actions Toshiba may take to address this situation. At that time, Toshiba reaffirmed its commitment to its nuclear projects in the United States with implementation of management changes and increased oversight. However, since that initial announcement, Westinghouse has engaged legal and financial bankruptcy advisors and is soliciting debtor-in-possession financing packages, significantly increasing the likelihood that Westinghouse will file bankruptcy in the near-term. We are also aware that some subcontractors have asserted that the Contractor has not made payments for work performed at the Vogtle project. Georgia Power, on behalf of the Co-owners, and we are analyzing potential contingency planning scenarios and have retained legal and financial advisors in the event the Contractor fails to remedy any payment deficiencies or Westinghouse files for bankruptcy protection. A failure by Westinghouse or Toshiba to perform its obligations, including as a result of a declaration of bankruptcy by either or both of Westinghouse and Toshiba, under the EPC Agreement or the related Toshiba parent guarantee, respectively, could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4.

In February 2017, the Contractor also provided Georgia Power, as agent for the Co-owners, with a preliminary schedule for revised forecasted in-service dates of December 2019 for Unit No. 3 and September 2020 for Unit No. 4, delays of six months and three months from the prior forecasted in-service dates of June 2019 and June 2020, respectively. The Contractor, Georgia Power and other Co-owners are continuing to review the schedule supporting these revised dates which must ultimately be reconciled with an integrated project schedule. Based on this continued schedule verification, at this time, we believe that the revised in-service dates of December 2019 and September 2020 do not appear to be achievable. To the extent that the Contractor is unable to meet the current revised forecasted in-service dates, such delay could have a material impact on the cost and schedule for Vogtle Units No. 3 and No. 4. We believe the Contractor is responsible for any related costs for not achieving the schedule and performance guarantees in the EPC Agreement. The EPC Agreement provides that the Contractor will begin to incur delay liquidated damages if the nuclear fuel loading dates for Unit No. 3 and No. 4 go beyond December 31, 2018 and December 31, 2019, respectively.

Our project budget for Vogtle Units No. 3 and No. 4, which includes capital costs and allowance for funds used during construction, is currently $5,000,000,000. As of December 31, 2016, our total investment in the additional Vogtle units was $3,269,000,000. Although many factors could increase our project budget, we do not anticipate that the announced six and three month delays to the forecasted in-service dates for Units No. 3 and No. 4, respectively, will change our current project budget. In the event the Contractor is unable to meet the revised forecasted in-service dates, we anticipate that each month of additional delay in the near-term will cost us approximately $20,000,000, including financing and owner's costs, net of liquidated damages. Further, the failure of Westinghouse or Toshiba to perform its obligations under the EPC Agreement or the related Toshiba parent guarantee, respectively, could have a material impact on the cost and schedule of

Vogtle Units No. 3 and No. 4 and could significantly impact our project budget.

Substantial risks remain that continued challenges with the Contractor's construction performance, including labor productivity, fabrication, delivery, assembly and installation of plant systems, structures and components, or other issues could further impact the project schedule and cost. In addition, there have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state levels, and additional challenges may arise as construction proceeds. Processes are in place that are designed to assure compliance with the requirements specified in the Westinghouse AP1000 Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the Nuclear Regulatory Commission. Further, various design and other licensing-based compliance matters, including the timely resolution of inspections, tests, analyses and acceptance criteria by the Nuclear Regulatory Commission may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners, the Contractor, or both.

Future claims by the Contractor or Georgia Power, on behalf of the Co-owners, could arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the EPC Agreement and may be resolved through litigation after the completion of nuclear fuel load for both units. The failure of Westinghouse or Toshiba to fulfill its obligations under the EPC Agreement or the related Toshiba parent guarantee, respectively, as a result of a bankruptcy filing would also be expected to lead to litigation and we would expect Georgia Power, on behalf of the Co-Owners, to aggressively pursue and seek to enforce all potential Co-owner rights and remedies.

Despite the uncertainty surrounding the EPC Agreement and the financial health of Westinghouse and Toshiba, at this time we remain committed to continuing to work on the Vogtle project. We will continue to monitor and evaluate developments related to the Vogtle project and will endeavor to undertake a course of action that we believe will advance the long-term interests of our members. Georgia Power has stated that it is prepared to take appropriate actions on behalf of the Co-owners should Westinghouse or Toshiba fail to perform its obligations under the EPC Agreement and the related Toshiba parent guarantee, respectively.

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

9. Employee benefit plans:

Our retirement plan is a contributory 401(k) that covers substantially all employees. An employee may contribute, subject to IRS limitations, up to 60% of his or her eligible annual compensation. At our discretion, we may match the employee's contribution and have done so each year of the plan's existence. Our current policy is to match the employee's contribution as long as there is sufficient margin to do so. The match, which is calculated each pay period, currently can be equal to as much as three-quarters of the first 6% of an employee's eligible compensation, depending on the amount and timing of the employee's contribution. Our contributions to the matching feature of the plan were approximately $1,371,000, $1,310,000 and $1,205,000 in 2016, 2015 and 2014, respectively.

Our 401(k) plan also includes an employer retirement contribution feature, which subject to IRS limitations, contributes 11% of an employee's eligible annual compensation. Prior to 2016, the effective rate of the employer retirement contribution was 8%. Our contributions to the employer retirement contribution feature of the 401(k) plan were approximately $3,678,000, $2,611,000 and $2,441,000 in 2016, 2015 and 2014, respectively.

10. Nuclear insurance:

The Price-Anderson Act limits public liability claims that could arise from a single nuclear incident to $13,400,000,000. This amount is covered by private insurance and a mandatory program of deferred premiums that could be assessed against all owners of nuclear power reactors. Such private insurance provided by American Nuclear Insurers (ANI), 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 NRC. 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 $127,000,000 per incident for each licensed reactor operated by it, but not more than $19,000,000 per reactor per incident to be paid in a calendar year. On the basis of our ownership interest in four nuclear reactors, we could be assessed a maximum of $153,000,000 per incident, but not more than $23,000,000 in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years, and exclude any applicable state premium taxes. The next scheduled adjustment is due no later than September 10, 2018.

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 $1,500,000,000 for members' operating nuclear generating facilities. Additionally, there is coverage through NEIL for decontamination, excess property insurance, and premature decommissioning coverage up to $1,250,000,000 for nuclear losses in excess of the $1,500,000,000 primary coverage. On April 1, 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750,000,000 for non-nuclear losses in excess of the $1,500,000,000 primary coverage.

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

Under each of the NEIL policies, members are subject to retroactive assessments in proportion to their premiums, if losses each year exceed the accumulated reserve funds available to the insurer. The portion of the current maximum annual assessment for Georgia Power that would be payable by Oglethorpe based on ownership share, is limited to approximately $40,000,000.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3,200,000,000 plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are next to be applied toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to Georgia Power, for the benefit of all the co-owners, or to bond trustees as may be appropriate under the policies and applicable trust indentures.

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

11. Commitments:

a. Operating leases

As of December 31, 2016, our estimated minimum rental commitments for our railcar leases for use at our coal-fired facilities over the next five years and thereafter are as follows:

	(dollars in thousands)
2017	$ 5,277
2018	5,277
2019	2,923
2020	583
2021	–
Thereafter	–

These railcar leasing costs are added to the cost of the fossil inventories and are recognized in fuel expense. Rental expenses totaled $4,456,000, $4,849,000 and $5,139,000 in 2016, 2015 and 2014, respectively.

b. Fuel

To supply a portion of the fuel requirements to our generating units, Southern Nuclear on our behalf for nuclear fuel, and Georgia Power, on our behalf for coal, have entered into various long-term commitments for the procurement of coal and nuclear fuel. The contracts in most cases contain provision for price escalations, minimum and maximum purchase levels and other financial commitments. The value of the coal commitments is based on maximum coal prices and minimum volumes as provided in the contracts and does not include taxes, transportation, government impositions or railcar costs. For further discussion of total nuclear fuel expense, see Note 1h. As of December 31, 2016, our estimated minimum long-term commitments are as follows:

	(dollars in thousands)	
	Coal	**Nuclear Fuel**
2017	$ 19,164	$ 46,600
2018	10,837	35,600
2019	4,972	30,500
2020	–	25,700
2021	–	30,800
Thereafter	–	60,000

12. Contingencies and Regulatory Matters:

We do not anticipate that the liabilities, if any, for any current proceedings against us will have a material effect on our financial condition or results of operations. However, at this time, the ultimate outcome of any pending or potential litigation cannot be determined.

Patronage Capital Litigation

On March 13, 2014, a lawsuit was filed in the Superior Court of DeKalb County, Georgia, against us, Georgia Transmission and three of our member distribution cooperatives. Plaintiffs filed an amended complaint on July 28, 2014. The amended complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives and seeks to certify a defendant class of all but one of our 38 members. It was filed by four former consumer-members of four of our members on behalf of themselves and a proposed class of all former consumer-members of our members. Plaintiffs claim that approximately 30% of all the defendants' total allocated patronage capital belongs to former consumer-members. Plaintiffs also allege that patronage capital owed to former consumer-members includes patronage capital allocated by us to our members but not yet distributed to our members. Plaintiffs claim that the patronage capital of former consumer-members held by defendants and the proposed defendant class should be retired immediately when the consumer-members end their membership by terminating service, or alternatively, according to a revolving schedule of no longer than 13 years from the date of its allocation and seek relief to effect such retirements. Plaintiffs further seek to require the defendants to adjust rates in order to establish and maintain reasonable reserves to fund patronage capital retirements on this basis. Plaintiffs also claim that defendants and the proposed defendant class should be required to adopt policies to periodically retire the patronage capital of all consumer-members on a revolving schedule of no longer than 13 years from the date of its allocation. Our first mortgage indenture restricts our ability to distribute patronage capital. Although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level sufficient so that we could comply with the current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiffs' demands would be significant for a period of years.

On August 20, 2014, a second patronage capital lawsuit was filed in the Superior Court of DeKalb County against us, Georgia Transmission, and two of our member distribution cooperatives. The case was filed by two current consumer-members of the two member distribution cooperatives named in the lawsuit. Similar to the above described litigation, this complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives; however, one notable difference is that the first case, described above, seeks to bring claims on behalf of former members while this second case seeks to bring claims on behalf of current members. The plaintiffs allege that the defendants have (i) retained patronage capital for an unreasonably long period of time; (ii) conspired with each other to deprive consumer-members of their patronage capital; and (iii) breached bylaw provisions allegedly requiring that patronage capital be retired when the financial condition of the cooperative will not be impaired. The plaintiffs seek unspecified damages and equitable relief, including an order declaring that the defendants be required to retire patronage capital "according to a regular, reasonable revolving plan." Similarly to the litigation described above, although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level where we could comply with current patronage capital distribution restrictions, and the rate increases required to meet the

Plaintiff's demands could be significant for a period of years. The plaintiffs seek to certify three plaintiffs' classes but do not seek to certify a defendants' class.

In May 2015, the Superior Court judge appointed a special master to oversee all pre-trial issues relating to these cases, including motions to dismiss that we and the other defendants filed in connection with each lawsuit. In September, the special master issued proposed orders to the judge to grant our and the other defendants' motions to dismiss both patronage capital lawsuits on all counts.

On May 2, 2016, the Superior Court judge adopted the special master's proposed orders and granted our and the other defendants' motions to dismiss both of these lawsuits on all counts. On May 31, 2016, plaintiffs for both of the cases appealed the Court's decision to grant the motions to dismiss to the Georgia Court of Appeals.

We intend to defend vigorously against all claims in the above-described litigation.

Environmental Matters

As is typical for electric utilities, we are subject to various federal, state and local environmental laws which represent significant future risks and uncertainties. Air emissions, water discharges and water usage are extensively controlled, closely monitored and periodically reported. Handling and disposal requirements govern the manner of transportation, storage and disposal of various types of waste. We are also subject to climate change regulations that impose restrictions on emissions of greenhouse gases, including carbon dioxide, for certain new and modified facilities.

In general, these and other types of environmental requirements are becoming increasingly stringent. Such requirements may substantially increase the cost of electric service, by requiring modifications in the design or operation of existing facilities or the purchase of emission allowances. Failure to comply with these requirements could result in civil and criminal penalties and could include 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 and future environmental laws or regulations. Should we fail to be in compliance with these requirements, it would constitute a default under those debt instruments. We believe that we are in compliance with those environmental regulations currently applicable to our business and operations. Although it is our intent to comply with current and future regulations, we cannot provide assurance that we will always be in compliance.

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

Additionally, litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the United States. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief, personal injury and property damage allegedly caused by coal combustion residue, greenhouse gas and other emissions have become more frequent.

13. Purchase Agreements:

On April 11, 2014, we signed a precedent agreement with Transcontinental Gas Pipeline Company, LLC (Transco) for additional firm natural gas transportation to our Smith facility. The additional firm transportation is contingent upon the construction of a new natural gas pipeline by Transco. Total fixed charges over the 25-year base term will be approximately $942,500,000. Our obligation to make payments begins when the pipeline expansion project is placed into service, which is projected to be July 2017.

14. Quarterly financial data (unaudited):

Summarized quarterly financial information for 2016 and 2015 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(dollars in thousands)			
2016				
Operating revenues	**$ 348,161**	**$ 379,343**	**$ 431,013**	**$ 348,714**
Operating margin	**71,093**	**74,148**	**70,929**	**39,494**
Net margin	**20,598**	**23,277**	**18,630**	**(12,160)**
2015				
Operating revenues	$ 339,778	$ 343,741	$ 368,664	$ 297,642
Operating margin	68,260	63,494	69,287	56,417
Net margin	15,369	10,852	15,908	6,212

The negative net margins in the fourth quarter of 2016 and the decrease in net margin in the fourth quarter of 2015 were due to reductions to revenue requirements in order to achieve the targeted margins for interest ratio of 1.14.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Members of Oglethorpe Power Corporation

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Oglethorpe Power Corporation (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of revenues and expenses, comprehensive margin, patronage capital and membership fees and accumulated other comprehensive (deficit) margin, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Oglethorpe Power Corporation at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Atlanta, Georgia
March 27, 2017

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, 2016 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 (2013 framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation under the framework in Internal Control – Integrated Framework (2013 framework) issued by Committee of Sponsoring Organizations, our management concluded that our internal control over financial reporting was effective as of December 31, 2016 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2016, 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 outside directors. Our bylaws divide member director positions among the member scheduling groups specifically described in the bylaws, referred to as the ''member groups.'' There are currently five member groups and, except for Group 5, each member group is represented by two member directors. Of each member group's two directors, one must be a general manager of a member in that member group and one must be a director of a member in that member group. Jackson Electric Membership Corporation is the only member in Group 5 and has only one director. The bylaws permit expansion of the number of member groups and changes in the composition of member groups. Formation of new member groups and changes in the composition of member groups are subject to certain required member approvals, and the requirement that the composition of the member groups at Oglethorpe, Georgia Transmission and Georgia System Operations be identical, except in cases where a member is no longer a member of one or more of Oglethorpe, Georgia Transmission or Georgia System Operations. The number of member director positions will change if additional member groups are formed or a member group ceases to exist. The bylaws also provide for three at-large member director positions which must each be filled by a director of one of our members.

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

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

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

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

Election of our Board of Directors

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

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

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

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

Board of Directors Leadership Structure

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

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

Executive Officer and Director Biographies

Our executive officers and directors are as follows:

Name	Age	Position
Executive Officers:		
Michael L. Smith	57	President and Chief Executive Officer
Michael W. Price	56	Executive Vice President and Chief Operating Officer
Elizabeth B. Higgins	48	Executive Vice President and Chief Financial Officer
William F. Ussery	52	Executive Vice President, Member and External Relations
Annalisa M. Bloodworth	39	Senior Vice President and General Counsel
Jami G. Reusch	54	Vice President, Human Resources
Heather Teilhet	41	Vice President, Governmental Affairs
Directors:		
Bobby C. Smith, Jr.	63	Chairman and At-Large Director
Marshall S. Millwood	67	Vice-Chairman and At-Large Director
Jimmy G. Bailey	68	At-Large Director
George L. Weaver	68	Member Group Director (Group 1)
James I. White	71	Member Group Director (Group 1)
Danny L. Nichols	52	Member Group Director (Group 2)
Sammy G. Simonton	75	Member Group Director (Group 2)
Randy Crenshaw	64	Member Group Director (Group 3)
M. Anthony Ham	65	Member Group Director (Group 3)
Fred A. McWhorter	70	Member Group Director (Group 4)
Jeffrey W. Murphy	53	Member Group Director (Group 4)
Ernest A. "Chip" Jakins III	47	Member Group Director (Group 5)
Wm. Ronald Duffey	75	Outside Director

Executive Officers

Overview

We are managed and operated under the direction of a president and chief executive officer who is appointed by our board of directors. Our president and chief executive officer selects the remainder of the executive team. Each of our executive officers has entered into an employment contract with us that provides for minimum annual base salary and performance pay. See "EXECUTIVE COMPENSATION – Compensation Discussion and Analysis – Employment Agreements" for further discussion of these agreements.

Executive Officer Biographies

Michael L. Smith is our President and Chief Executive Officer and has served in that capacity since November 2013. Prior to joining Oglethorpe, Mr. Smith served as Georgia Transmission's President and Chief Executive Officer from 2005 to 2013 after he joined Georgia Transmission as its Senior Vice President and Chief Financial Officer in 2003. From 2002 to 2003, Mr. Smith co-founded and served as the Executive Director of the Committee of Chief Risk Officers. From 1997 to 2002, Mr. Smith held multiple positions at

Mirant Corporation, most recently as Vice President and Global Risk Officer. From 1994 to 1997, he was Manager of Planning and Evaluation for Vastar Resources and prior to that he worked at ARCO in various positions from 1983 to 1994. Mr. Smith has a Bachelor's degree in Business Law and a Masters of Business Administration in Finance from Louisiana State University. Mr. Smith is on the board of directors for both the SERC Reliability Corporation and Association of Edison Illuminating Companies. Mr. Smith is also on the board of directors of the Georgia Chamber of Commerce and for ACES Power Marketing.

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 on the board of directors for SERC Reliability Corporation and ACES Power Marketing.

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

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

Annalisa M. Bloodworth is our Senior Vice President and General Counsel and has served in that capacity since January 2017. Ms. Bloodworth joined Oglethorpe in 2010 and served in various roles prior to taking her current position, most recently as Deputy General Counsel. Prior to joining Oglethorpe, Ms. Bloodworth was in private practice at Eversheds Sutherland (US) LLP. In addition to energy, her legal experience includes significant work in commercial development, real estate, regulatory compliance, and construction contracting. Ms. Bloodworth is a graduate of Trinity University where she earned a Bachelor of Arts in Economics and Emory University School of Law where she earned her Juris Doctor degree. Ms. Bloodworth is a member of Leadership Georgia and presently serves on the Corporate Leadership Council of the Fernbank Natural History Museum and the Emory University School of Law Alumni Board.

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.

Heather H. Teilhet is our Vice President, Governmental Affairs and has served in that capacity since January 2017. Prior to joining us, Ms. Teilhet served as Vice President of Government Relations for Georgia Electric Membership Corporation from 2010 to 2016, where she represented Georgia's 41 electric cooperatives before the Georgia General Assembly, the U.S. Congress and certain regulatory agencies. Prior to joining Georgia EMC, she served as a senior staff member for Georgia Governor Sonny Perdue and as a staff member for Georgia Governor Roy Barnes. Ms. Teilhet graduated from the University of Georgia and holds a Masters in Public Administration from Georgia State University.

Board of Directors

Director Qualifications

As required by our bylaws, all of the members of our board of directors, except for the 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; we have no 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

Jimmy G. Bailey is an at-large director. Mr. Bailey has served on our board of directors since September 2015 and his present term will expire in March 2019. Mr. Bailey is a member of the construction project committee. Mr. Bailey is a director of Diverse Power Incorporated, an EMC. Mr. Bailey has owned and operated a construction contracting business since 1970. He also serves as Chairman of Kudzu Networks Inc., a subsidiary of Diverse Power, and is President of Georgia Directors Association.

Randy Crenshaw is a member group director (group 3). Mr. Crenshaw has served on our board of directors since March 2016, and his present term will expire in March 2019. He is a member of the compensation committee. Mr. Crenshaw is President and Chief Executive Officer of Irwin Electric Membership Corporation and Middle Georgia Electric Membership Corporation. Mr. Crenshaw also serves on the board of directors for Georgia Electric Membership Corporation, where he is the secretary-treasurer and on the executive committee, and the Georgia Cooperative Council, where he serves as chairman. He is also on the board of directors for Green Power EMC, Smarr EMC and GRESCO Utility Supply, Inc and is a former member of Georgia Systems Operations board of directors. He is also past president of the Irwin/Ocilla Chamber of Commerce and a member of the Irwin Development Board.

Wm. Ronald Duffey is an outside director. Mr. Duffey has served on our board of directors since March 1997, and his present term will expire in March 2018. He is the chairman of the audit committee and served as special liaison between senior management and the board during the search for a successor president and chief executive officer from June to November 2013. Mr. Duffey is the retired Chairman of the Board of Directors of Peachtree National Bank in Peachtree City, Georgia, a wholly owned subsidiary of Synovus Financial Corp. Prior to his employment in 1985 with Peachtree National Bank, Mr. Duffey served as Executive Vice President and Member of the Board of Directors for First National Bank in Newnan, Georgia. He holds a Bachelor of Business Administration degree from Georgia State College with a concentration in finance and has completed banking courses at the School of Banking of the South, Louisiana State University, the American Bankers Association School of Bank Investments, and The

Stonier Graduate School of Banking, Rutgers University. Mr. Duffey is Vice Chair of the board of directors of Piedmont Healthcare, where he is also Chair of the Audit and Compliance Committee and serves on the Executive Committee, Executive Performance and Compensation Committee and Governance and Nominating Committee. Mr. Duffey is also a member of the board of directors of the Georgia Chamber of Commerce.

M. Anthony Ham is a member group director (group 3). Mr. Ham has served on our board of directors since March 2004, and his present term will expire in March 2020. He is 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 has served as a director of Okefenoke Rural Electric Membership Corporation since 1994 and was appointed Secretary and Treasurer in 2007.

Ernest A. "Chip" Jakins III is a member group director (group 5). Mr. Jakins has served on our board of directors since 2014, and his present term will expire in March 2020. Mr. Jakins is a member of the construction project committee and the compensation committee. Mr. Jakins is currently the President and Chief Executive Officer of Jackson Electric Membership Corporation and was previously President and Chief Executive Officer of Carroll Electric Membership Corporation. He also serves as a director for Georgia System Operations, where he is a member of the audit committee, for Georgia Electric Membership Corporation where he is a member of the Executive Committee and Workers Compensation Fund Executive Committee, and for Green Power EMC. He is also a member of the Georgia Chamber of Commerce.

Fred A. McWhorter is a member group director (group 4). Mr. McWhorter has served on our board of directors since September 2012, and his present term will expire in March 2019. He is a member of the construction project committee. Mr. McWhorter serves as Vice Chairman of the Rayle Electric Membership Corporation board of directors. Mr. McWhorter also serves on the board of directors for Georgia Electric Cooperative. He is the owner of F.A. McWhorter Poultry Farms.

Marshall S. Millwood is the Vice-Chairman of the Board and an at-large director. Mr. Millwood has served on our board of directors since March 2003, and his present term will expire in March 2018. He is the chairman of the compensation 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.

Jeffrey W. Murphy is a member group director (group 4). Mr. Murphy has served on our board of directors since March 2004, and his present term will expire in March 2018. He is 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 Georgia Energy Cooperative.

Danny L. Nichols is a member group director (group 2). Mr. Nichols has served on our board of directors since March 2011, and his present term will expire in March 2020. Mr. Nichols is the chairman of the construction project committee and also serves on the compensation committee. Mr. Nichols is the General Manager of Colquitt Electric Membership Corporation.

Sammy G. Simonton is a member group director (group 2). Mr. Simonton has served on our board of directors since October 2012, and his present term will expire in March 2018. He is a member of the compensation committee. Mr. Simonton is a director of Walton Electric Membership Corporation. Mr. Simonton is currently the owner of Simonton Farms and has previous business affiliations with Meridian Homes, Moreland Altobelli Associates, Inc. and the Georgia Department of Transportation.

Bobby C. Smith, Jr. is the Chairman of the Board and an at-large director. Mr. Smith has served on our board of directors since May 2008, acting as Chairman since September 2015, and his present term will expire in March 2020. Mr. Smith is a farmer. He is a member of the board of directors of Planters Electric Membership Corporation. He also serves on the board of directors for Georgia Electric Membership Corporation and is Chairman of the Board of the Screven County Development Authority and a member of the Sylvania Lions Club.

George L. Weaver is a member group director (group 1). Mr. Weaver has served on our board of directors since March 2010, and his present term will expire in March 2019. He is a member of the audit committee. Mr. Weaver has been employed by Central Georgia Electric Membership Corporation since 1970 and is currently serving as President and Chief Executive Officer. Mr. Weaver is currently a director of Southeastern Data Cooperative and is a former director of Federated Rural Electric Insurance Corporation.

James I. White is a member group director (group 1). Mr. White has served on our board of directors since March 2012, and his present term will expire in March 2020. He is a member of the audit committee. Mr. White has served as a director of Snapping Shoals Electric Membership Corporation since 1995. Mr. White is the owner and president of Realty South Inc. and the owner of T.K. White Real Estate Co. and is a member of the Metro South Association of Realtors and Georgia Association of Realtors. Mr. White is also a member of the Henry County Chamber of Commerce and was involved with the Henry County Development Authority for over 20 years. He was previously vice president at the First National Bank in Crestview, Florida.

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 various aspects of our business, including all material aspects of our financial reporting functions as well as risk assessment and management. Its responsibilities related to financial reporting 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 audit committee also reviews our policy standards and guidelines for risk assessment and risk management as discussed further under "– Board of Directors' Role in Risk Oversight." The members of the audit committee are currently Ronald Duffey, Jeffrey Murphy, George Weaver and James White. 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 our compensation programs as needed. Currently, the members of the compensation committee are Marshall Millwood, Randy Crenshaw, Anthony Ham, Chip Jakins, Danny Nichols and Sammy Simonton. Mr. Millwood is the chairman of the compensation committee.

Construction Project Committee. The construction project committee is responsible for reviewing and making recommendations to our board of directors with regards to major actions or commitments relating to new power plant construction projects and certain existing plant modification projects. Its responsibilities include reviewing and recommending to our board of directors final plant sites, project budgets (including certain modifications to project budgets) and project construction plans, and a quarterly reviewing of and reporting on the status of projects. The members of the construction project committee are currently Danny Nichols, Jimmy Bailey, Chip Jakins and Fred McWhorter. Mr. Nichols 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. 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. Additionally, management also develops and typically shares a corporate risk map with our audit committee. The corporate risk map depicts the probability of occurrence and the potential severity for each significant corporate risk.

At each regular meeting of the board of directors, management provides the board with reports on significant changes related to the top strategic risks and opportunities facing us and a revised version of the strategic issues matrix that highlights any revisions to the matrix. The audit committee chairman also provides the board of directors with updates on overall corporate risk exposure. Furthermore, the board of directors receives risk analysis reports that identify key risks that could create variances from our approved annual budget and long-range forecasts and discuss 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 and compliance 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 and compliance committee, which are described below, as well as quarter-end reports, which include changes to derivative hedge positions and overall corporate risk exposure. Additionally, the audit committee provides oversight over corporate ethics and compliance matters and receives regular reports on compliance, which include, but are not limited to, the review of i) significant compliance issues, ii) significant audits/examinations by governmental or other regulatory agencies, and iii) significant regulatory proceedings. The risk management and compliance committee, comprised of our chief executive officer, chief operating officer, chief financial officer, and the executive vice president of member and external relations, provides general oversight over all of our risk management and compliance activities, including but not limited to commodity trading, fuels management, insurance procurement, debt management, investment portfolio management, environmental and electric reliability compliance and cyber-security. The risk management and compliance committee has implemented comprehensive policies and procedures, consistent with current board policies, which govern our activities pertaining to market, compliance/regulatory and other risks. For further discussion about our risk management and compliance committee and its activities, see "Quantitative And Qualitative Disclosures About Market Risk."

Code of Ethics and Code of Conduct

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

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Executive Summary

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

Components of Total Compensation

The compensation committee determined that compensation packages for the fiscal year ended December 31, 2016 for our executive officers should be comprised of the following three primary components:

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

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

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

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

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

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

Benefits. The benefits program is designed to allow executive officers to choose the benefit options that best meet their needs. Our president and chief executive officer recommends changes to the benefits program or level of benefits that all executive officers, including our president and chief executive officer, receive to the compensation committee. The compensation committee then reviews and recommends changes to the board of directors for its approval. To meet the health and welfare needs of our 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 each executive officer with life insurance coverage of two times the officer's base salary, up to $800,000, as well as disability insurance at a level equal to 60% of the officer's base salary. The health, life and disability insurance coverage we provide to our executive officers is consistent with the coverage we provide to our employees generally.

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. In 2016, we contributed an additional amount equal to 11% of an executive officer's pay per period. See "– Nonqualified Deferred Compensation" below for additional information regarding our contributions to our executive officers' retirement plans.

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

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

Establishing Compensation Levels

Role of the Compensation Committee. The compensation committee annually reviews each of the components of our compensation program for our officers, directors and employees and recommends any changes to our board of directors for approval. To aid in this review, the compensation committee receives a comprehensive report on an annual basis regarding all facets of our compensation program. In order to have a compensation program that is internally consistent and equitable, the compensation committee considers several subjective and objective factors when determining the compensation program. The compensation committee also approves our performance pay program including, the corporate goals related to such program.

The compensation committee currently reviews and recommends to the board of directors for approval the compensation, including any bonus, for our president and chief executive officer. Some of the factors reviewed include the position's duties and responsibilities, the individual's job performance, experience, longevity of service and overall value provided for our members. Each year, the compensation committee reviews the employment agreement of our president and chief executive officer and makes a recommendation to our board of directors whether it should be extended.

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

Role of Management. Our president and chief executive officer is the key member of management involved in our compensation process. He annually reviews the compensation of our other executive officers and in certain circumstances provides an adjustment to the executive officers' base salaries. Some of the factors the president and chief executive officer considers include the person's relative responsibilities and duties, experience, job performance, longevity of service and overall value provided for our members. Our president and chief executive officer also reviews the executive officers' employment agreements on an annual basis and makes an affirmative decision whether each should be extended. Our president and chief executive officer reports the executive officers' salaries and determination whether to extend the employment agreements to the compensation committee and board of directors annually.

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

Role of the Board of Directors. Our board of directors must approve changes recommended by the compensation committee before the changes may take effect. These approvals include the compensation of our president and chief executive officer, the extension of the president and chief executive officer's employment agreement, and the components of our compensation program each year.

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

Corporate Goals for Performance Pay

We choose to tie performance compensation to selected corporate goals that most appropriately measure our achievement of our strategic objectives. For 2016, our performance measures were divided into the following categories: i) safety, ii) operations, iii) construction and project management, iv) corporate compliance, v) financial and vi) quality. Targeted performance measures in these categories are designed to help us accomplish our corporate goals which will benefit our members, employees and promote responsible environmental stewardship.

The maximum performance pay each executive officer can receive is 20% of his or her salary and in order to receive the full 20%, 100% of the performance measures must be achieved. The performance measures are weighted to align with our current strategic focus, and goals are reviewed annually, and adjusted in order to reflect any changes in our strategic focus. For example, in 2016, we added a new goal to assess our performance in obtaining adequate gas availability for Smith. We also review and refine these goals annually and make adjustments as necessary to ensure that we are consistently stretching our expectations and performance. Although some performance measures may stay the same, the applicable threshold may become more difficult. The following provides an overview of the purposes of each category of our corporate goals:

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

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

Construction and Project Management. Our construction and project management goals measure our involvement and management regarding construction at our owned and co-owned generating facilities. Our most significant project is the construction of Vogtle Units No. 3 and No. 4. One of the goals measures how well we are managing the project in our role as a Co-owner. Performance is based on our participation on the Project Management Board, the degree and effectiveness of oversight involvement, understanding of the project status and project issues, and timeliness and usefulness of project communications to our members and our board of directors. Our president and chief executive officer will assign a score based on his assessment of the overall effectiveness of our management of the project and submit the score to the construction committee of our board of directors for approval. Other components measure construction progress at the Vogtle project as well as construction projects that we directly oversee, and we measure success based on meeting applicable project deadlines.

Corporate Compliance. Our corporate compliance goals are divided into two categories – environmental and electric reliability standards. The environmental goals promote our commitment to responsible environmental stewardship while providing reliable and affordable energy. We measure our performance by the number of environmental incidents, such as spills, which not only increase costs for our members but may cause environmental damage. Electric reliability standards compliance is measured by reviewing our performance as determined by standards set by the electric reliability organizations and through the continued development of a comprehensive cyber security program. In 2016, we added a new goal related to gas pipeline compliance requirements.

Financial. Our financial goals provide direct benefits to our members by lowering power costs. One goal is tied to specific financial performance while others focus on emphasizing importance of appropriate and effective internal controls. For example, the cost savings goal is designed to encourage staff to identify and implement strategies that result in cost savings or cost reductions in either the current year or in the long-term. Any cost savings included in this goal must be over and above what would generally be expected. Two other financial goals focus on our internal control over financial reporting.

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

Calculation of Performance Pay Earned

Performance pay earned by our executive officers is based entirely on our success in achieving each of our corporate goals. Annually, our board of directors approves a weighted system for determining performance pay whereby we assign a percentage to each of the goals, as noted below. Based on the achievement of each performance metric, a percentage of the weighted goal is available as performance pay to our executive officers. Each performance metric has a minimum threshold level that must be achieved before any performance pay is earned. If the actual performance for that metric meets the applicable threshold, then a pre-determined percentage of the percentage pay for that metric will be awarded. The percentage awarded will increase up to a maximum of 100% of the weighted goal if the maximum performance level of the performance metric is achieved. Threshold and maximum levels are reviewed annually and generally reset as necessary to demand ever improving corporate performance. Meeting the applicable thresholds is not guaranteed and requires diligence and hard work. Exceptional performance is required to reach the maximum goals.

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

Assessment of Performance of 2016 Corporate Goals

The specific corporate performance measures, thresholds, maximums and results for our executive officers' 2016 performance pay were the following:

Performance Category/ Description	Performance Measure	Threshold	Maximum	2016 Result	Weight	Weighted Goal Achieved
Safety						
Incident Rate	Lost Work Day Cases	0	0	0.0%	3.0%	3.00%
Safety Program[1]	Training and Meetings	50.0%	100.0%	100.0%	3.0%	3.00%
	Program Enhancements	50.0%	100.0%	100.0%	4.0%	4.00%
Operations[2]						
Oglethorpe Managed Fleet	Successful Starts	96.22-98.36%	100.0%	99.1%	4.0%	3.07%
	Successful Dispatch	92.5%	97.5%	98.5%	3.0%	2.99%
	Peak Season Availability	63.87-96.02%	96.90-99.74%	80.3%	19.0%	15.12%
	Smith Gas Availability	0%	100.0%	66.7%	1.0%	0.67%
Co-Owned Fleet	Coal Fleet Peak Season Equivalent Forced Outage Rate	4.00-4.75%	2.75%-3.50%	0.5%	1.33%	1.33%
	Coal Fleet Annual Equivalent Unplanned Unavailability Factor	5.00%	3.50-4.50%	2.8%	0.67%	0.67%
	Nuclear Fleet Capability Factor	91.1%	92.9%	95.3%	2.0%	2.0%
Construction and Project Management						
Vogtle Units No. 3 and No. 4	Oglethorpe Performance	0.0%	100.0%	100.0%	6.0%	6.00%
	Status of Project	0.0%	100.0%	75.0%	2.0%	1.50%
Oglethorpe Managed Projects	Status of Projects	0.0%	100.0%	100.0%	4.0%	4.00%
Corporate Compliance						
Environmental	Final Notices of Violation and Letters of Non-Compliance	1 (if fine is ≤ $5,000)	0	0	4.0%	4.00%
	Reportable Spills	1	0	0	4.0%	4.00%
Electric Reliability Standards	Mandatory Electric Reliability Standards Compliance	0 (if not administrative)	0	0	4.0%	4.00%
	Cyber Security Program	1	2	2	4.0%	4.00%
	Gas Pipeline Compliance	0	100.0%	100.0%	1.0%	1.00%
Financial						
Cost Saving	Current Year / Long-Term Savings	$0	$35,000,000	$38,645,000	12.0%	12.00%
Internal Control over Financial Reporting	Significant Deficiency or Material Weakness	0	0	0	1.5%	1.50%
	Control Deficiency	2	1	0	1.5%	1.50%
Quality						
Board Satisfaction	Board of Directors Survey	80.0%	100.0%	96.5%	15.0%	14.48%
Total					**100.0%**	**93.83%**

(1) Certain sub-goals have been aggregated for purposes of the table.

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

As noted above, we achieved 93.83% of our corporate goals for 2016. As a result, each of our executive officers received performance pay in an amount equal to 93.83% of 20% of his or her base salary. Set forth below is a table showing performance pay figures for each of our executive officers who received performance pay in 2016:

Executive Officer	Performance Pay*
Michael L. Smith	$ 129,103
Michael W. Price	77,691
Elizabeth B. Higgins	78,273
William F. Ussery	60,877
Charles W. Whitney	67,839

* Performance pay was calculated based on base salaries as of December 31, 2016. Actual compensation earned in 2016 is reported in the Summary Compensation Table below.

Employment Agreements

General

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

We have an employment agreement with Mr. Smith that extends through December 31, 2019. Mr. Smith's agreement will automatically renew pursuant to the corresponding provision of the agreement for successive one-year periods unless either party provides written notice not to renew the agreement twenty-four months before the expiration of any extended term. Each year, our board of directors makes an affirmative determination as to whether to provide such notice and no such notice has been provided. Mr. Smith's minimum annual base salary under his agreement is $630,000, and is subject to review and adjustment by our board of directors. Mr. Smith is eligible for an annual bonus and to participate in incentive compensation plans generally available to similarly situated employees, determined by our board of directors at its sole discretion. Mr. Smith is also entitled to an automobile or an automobile allowance during the term of the agreement. Mr. Smith's employment agreement contains severance pay provisions.

We also have employment agreements with Mr. Price, Ms. Higgins and Mr. Ussery. The current term of each agreement extends through December 31, 2018 and will automatically renew for successive one-year periods unless either party provides written notice not to renew the agreement twelve months before the expiration of any extended term. Each year, our president and chief executive officer makes an affirmative determination as to whether to provide such notice, and no such notices have been provided.

Minimum annual base salaries under these agreements are $414,000 for Mr. Price, $417,100 for Ms. Higgins and $324,400 for Mr. Ussery. Salaries are subject to review and possible adjustment as determined by the president and chief executive officer. Each executive is also eligible for an annual bonus and to participate in incentive compensation plans generally available to similarly situated employees, determined by us at our sole discretion. The employment agreements with Mr. Price, Ms. Higgins and Mr. Ussery contain severance pay provisions.

Assessment of Severance Arrangements

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

In determining that the president and chief executive officer's employment agreement was appropriate and necessary, the compensation committee considered Mr. Smith's role and responsibility within Oglethorpe in relation to the total amount of severance pay he would receive upon the occurrence of a severance event. The committee also considered whether the amount Mr. Smith would receive upon severance was appropriate given his total annual compensation. Upon review, the compensation committee determined that a maximum amount of severance compensation equal to a maximum of two year's compensation, plus benefits as described below, was an appropriate amount of severance compensation for Mr. Smith. The compensation committee believes that entering into a severance agreement with our president and chief executive officer is beneficial because it gives us a measure of stability in this position while affording us 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 considers 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 to significant wealth accumulation.

Pursuant to the terms of his employment agreement, Mr. Smith will be entitled to a lump-sum severance payment upon the occurrence of any of the following events: (1) we terminate his employment without cause; or (2) he resigns due to a demotion or material reduction of his position or responsibilities, a material reduction of his base salary, or a relocation of his principal office by more than 50 miles. The severance payment will equal Mr. Smith's then current base salary through the rest of the term of the agreement (with a minimum of one year's pay and a maximum of two years' pay), and is payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. In addition, Mr. Smith will be entitled to outplacement services and an amount equal to his costs for medical and dental continuation coverage under COBRA, each for the longer of one year or the remaining term of the agreement. Severance is payable only if Mr. Smith signs a form releasing all claims against us. The maximum severance that would be payable to Mr. Smith in the circumstances described above is $1,510,517.

The compensation committee also considered the total amount of compensation each of the other executive officers would receive upon the occurrence of a severance event. The compensation committee determined that it was 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 believes such severance compensation is necessary to address competitive concerns and offset any potential risk our executive officers face in the course of their employment.

Pursuant to the terms of their employment agreements, Mr. Price, Ms. Higgins and Mr. Ussery 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 one year of the executive's then current base salary, payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. 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. The maximum severance that would be payable to Mr. Price, Ms. Higgins and Mr. Ussery in the circumstances described above is $454,448, $458,715, and $402,902, respectively.

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, 2016 for filing with the SEC.

Respectfully Submitted

The Compensation Committee

Randy Crenshaw
M. Anthony Ham
Earnest A. Jakins III
Danny Nichols
Marshall S. Millwood
Sammy G. Simonton

Compensation Committee Interlocks and Insider Participation

Marshall S. Millwood, M. Anthony Ham, Sammy G. Simonton and George L. Weaver served as members of our compensation committee in 2016.

Mr. Weaver is a director of ours and also the president of Central Georgia Electric Membership Corporation. Central Georgia is a member of ours and has a wholesale power contract with us. Central Georgia's payments of $43.1 million to us in 2016 under its wholesale power contract accounted for 2.9% 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, 2016, 2015 and 2014.

Name and Principal Position	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	All Other Compensation(1)	Total
Michael L. Smith	2016	$ 683,550	$ –	$ 129,103	$136,677	$ 949,330
President and	2015	656,250	–	113,050	86,864	856,164
Chief Executive Officer	2014	630,000	–	112,405	76,077	818,482
Michael W. Price	2016	411,667	–	77,691	93,704	580,567
Executive Vice President and	2015	397,500	–	68,360	59,478	525,338
Chief Operating Officer	2014	382,968	–	68,692	66,590	518,250
Elizabeth B. Higgins	2016	414,750	–	78,273	79,465	569,914
Executive Vice President and	2015	400,333	–	68,873	61,701	530,907
Chief Financial Officer	2014	384,635	–	69,049	58,572	512,256
William F. Ussery	2016	322,833	–	60,877	78,308	462,018
Executive Vice President,	2015	313,333	–	53,833	48,547	415,713
Member and External Relations	2014	298,228	–	54,418	55,161	407,807
Charles W. Whitney(2)	2016	359,750	–	67,839	78,714	506,303
Former Senior Vice President,	2015	349,167	–	59,986	53,486	462,639
General Counsel	2014	330,071	–	60,663	53,112	443,846

(1) Figures for 2016 consist of matching contributions and contributions made by Oglethorpe under the 401(k) Retirement Savings Plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney of $35,000, $35,000, $35,000, $35,000, and $35,000, respectively; contributions by Oglethorpe to a nonqualified deferred compensation plan on behalf of Mr. Smith, Mr. Price, Ms. Higgins, Mr. Ussery, and Mr. Whitney, respectively of $84,598, $36,649, $31,699, $24,322 and $29,171; car allowances; paid time off, executive health benefits; customary holiday gifts and service awards.

(2) Mr. Whitney retired on December 31, 2016.

The following table sets forth the threshold and maximum awards available to the executive officers listed in the Summary Compensation Table who received performance pay for the fiscal year ended December 31, 2016.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards	
		Threshold	Maximum
Michael L. Smith President and Chief Executive Officer	N/A	$ 29,238	$ 137,592
Michael W. Price Executive Vice President and Chief Operating Officer	N/A	$ 17,595	$ 82,800
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	N/A	$ 17,727	$ 83,420
William F. Ussery Executive Vice President, Member and External Relations	N/A	$ 13,787	$ 64,880
Charles W. Whitney Former Senior Vice President, General Counsel	N/A	$ 15,364	$ 72,300

For an explanation of the criteria and formula used to determine the awards listed above, please refer to "– Compensation Discussion and Analysis – *Assessment of Performance of 2016 Corporate Goals*."

Nonqualified Deferred Compensation

We maintain a Fidelity Non-Qualified Deferred Compensation Program for each of the executive officers in the table below. This non-qualified deferred compensation program serves as a vehicle through which we can continue our employer retirement contributions to our executive officers beyond the IRS salary limits on the retirement plan ($270,000 as indexed).

The following table sets forth contributions for the fiscal year ended December 31, 2016 along with aggregate earnings for the same period.

Name	Executive Contributions in Last FY	Registrant Contributions in Last FY[1]	Aggregate Earnings in Last FY[2]	Aggregate Withdrawals/ Distributions in Last FY	Aggregate Balance at Last FYE
Michael L. Smith President and Chief Executive Officer	$ 25,000	$ 84,598	$ 10,651	$ –	$ 235,546
Michael W. Price Executive Vice President and Chief Operating Officer	–	36,649	12,486	–	214,654
Elizabeth B. Higgins Executive Vice President and Chief Financial Officer	–	31,699	19,049	–	226,654
William F. Ussery Executive Vice President, Member and External Relations	–	24,322	8,798	–	95,485
Charles W. Whitney Former Senior Vice President, General Counsel	–	29,171	3,610	–	89,011

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

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

Compensation Policies and Practices As They Relate to Our Risk Management

We believe that our compensation policies and practices for all employees, including executive officers, do not create risks that are reasonably likely to have a material adverse effect on us.

Director Compensation

The following table sets forth the total compensation paid or earned by each of our directors for the fiscal year ended December 31, 2016.

Name	Total Fees Earned or Paid in Cash
Member Directors	
Jimmy G. Bailey	$ 15,200
C. Hill Bentley[1]	$ 2,100
Randy Crenshaw[2]	$ 9,400
M. Anthony Ham	$ 13,400
Ernest A. "Chip" Jakins III	$ 10,400
Fred A. McWhorter	$ 11,400
Marshall S. Millwood, Vice-Chairman	$ 12,200
Jeffrey W. Murphy	$ 11,900
Danny L. Nichols	$ 11,600
Bobby C. Smith, Jr., Chairman	$ 14,740
Sammy G. Simonton	$ 13,400
George L. Weaver	$ 14,500
James I. White	$ 14,900
Outside Director	
Wm. Ronald Duffey	$ 32,100

(1) Mr. Bentley did not stand for re-election at our March 2016 annual meeting of the members.

(2) Mr. Crenshaw was elected to our board of directors in March 2016.

During 2016, we paid our member directors a fee of $1,200 per board meeting and $800 per day for attending committee meetings, other meetings, or other official business approved by the chairman of the board of directors. Member directors are paid $600 per day for attending the annual meeting of members and member advisory board meetings and $300 per day for participation by video conference for a meeting of the advisory board. Our outside director was paid a fee of $5,500 per board meeting for four meetings a year and a fee of $1,000 per board meeting for the remaining other board meetings held during the year. Our outside director was also paid $1,000 per day for attending committee meetings, annual meetings of the members or other official business. In addition, we reimburse all directors for out-of-pocket expenses incurred in attending a meeting. All directors are paid $100 per day when participating in meetings by conference call. The chairman of the board of directors is paid an additional 20% of his director's fee per board meeting for time involved in preparing for the meetings. The audit committee financial expert is paid an additional $400 per audit committee meeting for the time involved in fulfilling that role. If more than one meeting is held the same day, only one day's per diem is paid. Neither our outside director nor member directors receive any perquisites or other personal benefits from us.

Directors will be paid $600 per day, travel and out-of-pocket expenses for attending external training. We will also pay any fees charged for such training. Directors may choose one external training course per year to attend.

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

Randy Crenshaw is a director of ours and the President and Chief Executive Officer of Irwin Electric Membership Corporation and Middle Georgia Electric Membership Corporation. Irwin and Middle Georgia are members of ours and each has a wholesale power contract with us. Irwin's revenues of $9.1 million to us in 2016 under its wholesale power contract accounted for approximately 0.6% of our total revenues. Middle Georgia's revenues of $6.0 million to us in 2016 under its wholesale power contract accounted for approximately 0.4% of our total revenues.

Chip Jakins is a director of ours and the President and Chief Executive Officer of Jackson Electric Membership Corporation. Jackson is a member of ours and has a wholesale power contract with us. Jackson's revenues of $215.2 million to us in 2016 under its wholesale power contract accounted for approximately 14.3% of our total revenues.

Jeffrey Murphy is a director of ours and the President and Chief Executive Officer of Hart Electric Membership Corporation. Hart is a member of ours and has a wholesale power contract with us. Hart's revenues of $22.3 million to us in 2016 under its wholesale power contract accounted for approximately 1.5% of our total revenues.

Danny Nichols is a director of ours and is the General Manager of Colquitt Electric Membership Corporation. Colquitt is a member of ours and has a wholesale power contract with us. Colquitt's revenues of $47.0 million to us in 2016 under its wholesale power contract accounted for approximately 3.1% of our total revenues.

George Weaver is a director of ours and the President of Central Georgia Electric Membership Corporation. Central Georgia is a member of ours and has a wholesale power contract with us. Central Georgia's revenues of $43.1 million to us in 2016 under its wholesale power contract accounted for approximately 2.9% 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 Chip Jakins, satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet the requirements set forth in our bylaws. Mr. Jakins does not qualify as an independent director because he is the President and Chief Executive Officer of Jackson, an organization from which we received more than 5% of our gross revenues for the fiscal year ended December 31, 2016. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria in making this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For 2016 and 2015, fees for services provided by our independent registered public accounting firm, Ernst & Young LLP were as follows:

	2016	2015
	(dollars in thousands)	
Audit Fees(1)	**$ 498**	$ 483
Audit-Related Fees(2)	**57**	25
Tax Fees(3)	**26**	44
All Other Fees(4)	**2**	2
Total	**$ 583**	$ 554

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

(2) Other audit-related services.

(3) Professional tax services including tax consultation and tax return compliance.

(4) All other fees relates to a subscription to an on-line accounting research tool.

In considering the nature of the services provided by our independent registered public accounting firm, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed all non-audit services to be provided by independent registered public accounting firm to us with management prior to approving them to confirm that they were non-audit services permitted to be provided by our independent registered public accounting firm.

Pre-Approval Policy

The audit and permissible non-audit services performed by Ernst & Young LLP in 2016 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. The policy requires that requests for all services must be submitted to the audit committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

(2) Financial Statement Schedules

None applicable.

(3) Exhibits

Exhibits marked with an asterisk (*) are hereby incorporated by reference to exhibits previously filed by the Registrant as indicated in parentheses following the description of the exhibit.

Number		Description
*3.1(a)	–	Restated Articles of Incorporation of Oglethorpe, dated as of July 26, 1988. (Filed as Exhibit 3.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*3.1(b)	–	Amendment to Articles of Incorporation of Oglethorpe, dated as of March 11, 1997. (Filed as Exhibit 3(i)(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
3.2	–	Bylaws of Oglethorpe, as amended and restated, as of December 6, 2016.
*4.1	–	Amended and Restated Indenture of Trust, Deed to Secure Debt and Security Agreement No. 2, dated December 1, 1997, between Wilmington Trust Company and NationsBank, N.A. collectively as Owner Trustee, under Trust Agreement No. 2, dated December 30, 1985, with DFO Partnership, as assignee of Ford Motor Credit Company, and The Bank of New York Trust Company of Florida, N.A. as Indenture Trustee, with a schedule identifying three other substantially identical Amended and Restated Indentures of Trust, Deeds to Secure Debt and Security Agreements and any material differences. (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*4.2(a)	–	Lease Agreement No. 2, dated December 30, 1985, between Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Lessor, and Oglethorpe, Lessee, with a schedule identifying three other substantially identical Lease Agreements. (Filed as Exhibit 4.5(b) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
*4.2(b)	–	First Supplement to Lease Agreement No. 2 (included as Exhibit B to the Supplemental Participation Agreement No. 2 listed as 10.1.1(b)).

*4.2(c)	–	First Supplement to Lease Agreement No. 1, dated as of June 30, 1987, between The Citizens and Southern National Bank as Owner Trustee under Trust Agreement No. 1 with IBM Credit Financing Corporation, as Lessor, and Oglethorpe, as Lessee. (Filed as Exhibit 4.5(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
*4.2(d)	–	Second Supplement to Lease Agreement No. 2, dated as of December 17, 1997, between NationsBank, N.A., acting through its agent, The Bank of New York, as an Owner Trustee under the Trust Agreement No. 2, dated December 30, 1985, among DFO Partnership, as assignee of Ford Motor Credit Company, as the Owner Participant, and the Original Trustee, as Lessor, and Oglethorpe, as Lessee, with a schedule identifying three other substantially identical Second Supplements to Lease Agreements and any material differences. (Filed as Exhibit 4.5(d) to the Registrant's Form S-4 Registration Statement, File No. 333-42759.)
*4.3	–	Ninth Amended and Restated Loan Contract, dated as of September 2, 2014, between Oglethorpe and the United States of America, together with two notes executed and delivered pursuant thereto. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2014, File No. 000-53908.)
*4.4.1(a)	–	Indenture, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. (Filed as Exhibit 4.8.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.4.1(b)	–	First Supplemental Indenture, dated as of October 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1997B (Burke) Note. (Filed as Exhibit 4.8.1(b) to the Registrant's Form 10-Q for the quarterly period ended September 30, 1997, File No. 33-7591.)
*4.4.1(c)	–	Second Supplemental Indenture, dated as of January 1, 1998, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1997C (Burke) Note. (Filed as Exhibit 4.7.1(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1997, File No. 33-7591.)
*4.4.1(d)	–	Third Supplemental Indenture, dated as of January 1, 1998, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1997A (Monroe) Note. (Filed as Exhibit 4.7.1(d) to the Registrant's Form 10-K for the fiscal year December 31, 1997, File No. 33-7591.)
*4.4.1(e)	–	Fourth Supplemental Indenture, dated as of March 1, 1998, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998A (Burke) and 1998B (Burke) Notes. (Filed as Exhibit 4.7.1(e) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.4.1(f)	–	Fifth Supplemental Indenture, dated as of April 1, 1998, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998 CFC Note. (Filed as Exhibit 4.7.1(f) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.4.1(g)	–	Sixth Supplemental Indenture, dated as of January 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998C (Burke) Note. (Filed as Exhibit 4.7.1(g) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)
*4.4.1(h)	–	Seventh Supplemental Indenture, dated as of January 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1998A (Monroe) Note. (Filed as Exhibit 4.7.1(h) to the Registrant's Form 10-K for the fiscal year ended December 31, 1998, File No. 33-7591.)

*4.4.1(i)	–	Eighth Supplemental Indenture, dated as of November 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999B (Burke) Note. (Filed as Exhibit 4.7.1(i) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(j)	–	Ninth Supplemental Indenture, dated as of November 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999B (Monroe) Note. (Filed as Exhibit 4.7.1(j) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(k)	–	Tenth Supplemental Indenture, dated as of December 1, 1999, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee, relating to the Series 1999 Lease Notes. (Filed as Exhibit 4.7.1(k) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(l)	–	Eleventh Supplemental Indenture, dated as of January 1, 2000, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1999A (Burke) Note. (Filed as Exhibit 4.7.1(l) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(m)	–	Twelfth Supplemental Indenture, dated as of January 1, 2000, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 1999A (Monroe) Note. (Filed as Exhibit 4.7.1(m) to the Registrant's Form 10-K for the fiscal year ended December 31, 1999, File No. 33-7591.)
*4.4.1(n)	–	Thirteenth Supplemental Indenture, dated as of January 1, 2001, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2000 (Burke) Note. (Filed as Exhibit 4.7.1(n) to the Registrant's Form 10-K for the fiscal year ended December 31, 2000, File No. 33-7591.)
*4.4.1(o)	–	Fourteenth Supplemental Indenture, dated as of January 1, 2001, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2000 (Monroe) Note. (Filed as Exhibit 4.7.1(o) to the Registrant's Form 10-K for the fiscal year ended December 31, 2000, File No. 33-7591.)
*4.4.1(p)	–	Fifteenth Supplemental Indenture, dated as of January 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2001 (Burke) Note. (Filed as Exhibit 4.7.1(p) to the Registrant's Form 10-K for the fiscal year ended December 31, 2001, File No. 33-7591.)
*4.4.1(q)	–	Sixteenth Supplemental Indenture, dated as of January 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2001 (Monroe) Note. (Filed as Exhibit 4.7.1(q) to the Registrant's Form 10-K for the fiscal year ended December 31, 2001, File No. 33-7591.)
*4.4.1(r)	–	Seventeenth Supplemental Indenture, dated as of October 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002A (Burke) Note. (Filed as Exhibit 4.7.1(r) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(s)	–	Eighteenth Supplemental Indenture, dated as of October 1, 2002, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002B (Burke) Note. (Filed as Exhibit 4.7.1(s) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(t)	–	Nineteenth Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002C (Burke) Note. (Filed as Exhibit 4.7.1(t) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)

*4.4.1(u)	–	Twentieth Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002 (Monroe) Note. (Filed as Exhibit 4.7.1(u) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(v)	–	Twenty-First Supplemental Indenture, dated as of January 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2002 (Appling) Note. (Filed as Exhibit 4.7.1(v) to the Registrant's Form 10-K for the fiscal year ended December 31, 2002, File No. 33-7591.)
*4.4.1(w)	–	Twenty-Second Supplemental Indenture, dated as of March 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003 (FFB M-8) Note and Series 2003 (RUS M-8) Reimbursement Note. (Filed as Exhibit 4.7.1(w) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003, File No. 33-7591.)
*4.4.1(x)	–	Twenty-Third Supplemental Indenture, dated as of March 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003 (FFB N-8) Note and Series 2003 (RUS N-8) Reimbursement Note. (Filed as Exhibit 4.7.1(x) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003, File No. 33-7591.)
*4.4.1(y)	–	Twenty-Fourth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Appling) Note. (Filed as Exhibit 4.7.1(y) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(z)	–	Twenty-Fifth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Burke) Note. (Filed as Exhibit 4.7.1(z) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(aa)	–	Twenty-Sixth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003B (Burke) Note. (Filed as Exhibit 4.7.1(aa) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(bb)	–	Twenty-Seventh Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Heard) Note. (Filed as Exhibit 4.7.1(bb) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(cc)	–	Twenty-Eighth Supplemental Indenture, dated as of December 1, 2003, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2003A (Monroe) Note. (Filed as Exhibit 4.7.1(cc) to the Registrant's Form 10-K for the fiscal year ended December 31, 2003, File No. 33-7591.)
*4.4.1(dd)	–	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2004, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2004 (Burke) Note. (Filed as Exhibit 4.7.1(dd) to the Registrant's Form 10-K for the fiscal year ended December 31, 2004, File No. 33-7591.)
*4.4.1(ee)	–	Thirtieth Supplemental Indenture, dated as of December 1, 2004, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2004 (Monroe) Note. (Filed as Exhibit 4.7.1(ee) to the Registrant's Form 10-K for the fiscal year ended December 31, 2004, File No. 33-7591.)
*4.4.1(ff)	–	Thirty-First Supplemental Indenture, dated as of November 1, 2005, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2005 (Burke) Note. (Filed as Exhibit 4.7.1(ff) to the Registrant's Form 10-K for the fiscal year ended December 31, 2005, File No. 33-7591.)

*4.4.1(gg)	–	Thirty-Second Supplemental Indenture, dated as of November 1, 2005, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2005 (Monroe) Note. (Filed as Exhibit 4.7.1(gg) to the Registrant's Form 10-K for the fiscal year ended December 31, 2005, File No. 33-7591.)
*4.4.1(hh)	–	Thirty-Third Supplemental Indenture, dated as of May 1, 2006, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Series 2006 (FFB P-8) Note and Series 2006 (RUS P-8) Reimbursement Note. (Filed as Exhibit 4.7.1(hh) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006, File No. 33-7591.)
*4.4.1(ii)	–	Thirty-Fourth Supplemental Indenture, dated as of September 22, 2006, made by Oglethorpe to SunTrust Bank, as trustee, relating to the Amendment of Section 9.9 of the Original Indenture. (Filed as Exhibit 4.7.1(ii) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(jj)	–	Thirty-Fifth Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2006. (Filed as Exhibit 4.7.1(jj) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(kk)	–	Thirty-Sixth Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2006A (Burke) Note, Series 2006B-1 (Burke) Note, Series 2006B-2 (Burke) Note, Series 2006B-3 (Burke) Note, Series 2006B-4 (Burke) Note and Series 2006A (Monroe) Note. (Filed as Exhibit 4.7.1(kk) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(ll)	–	Thirty-Seventh Supplemental Indenture, dated as of October 1, 2006, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2006C-1 (Burke) Note, Series 2006C-2 (Burke) Note and Series 2006B (Monroe) Note. (Filed as Exhibit 4.7.1(ll) to the Registrant's Form 10-K for the fiscal year ended December 31, 2006, File No. 33-7591.)
*4.4.1(mm)	–	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Amendments to the Retained Indebtedness Note. (Filed as Exhibit 4.7.1(mm) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2007, File No. 33-7591.)
*4.4.1(nn)	–	Thirty-Ninth Supplemental Indenture, dated as of July 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2007 (FFB R-8) Note and Series 2007 (RUS R-8) Reimbursement Note. (Filed as Exhibit 4.7.1(nn) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2007, File No. 33-7591.)
*4.4.1(oo)	–	Fortieth Supplemental Indenture, dated as of October 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2007. (Filed as Exhibit 4.7.1(oo) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2007, File No. 33-7591.)
*4.4.1(pp)	–	Forty-First Supplemental Indenture, dated as of October 1, 2007, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2007A (Appling) Note, Series 2007B (Appling) Note, Series 2007A (Burke) Note, Series 2007B (Burke) Note, Series 2007C (Burke) Note, Series 2007D (Burke) Note, Series 2007E (Burke) Note, Series 2007F (Burke) Note and Series 2007A (Monroe) Note. (Filed as Exhibit 4.7.1(pp) to the Registrant's Form 10-Q for the quarterly period ended September 30, 2007, File No. 33-7591.)

*4.4.1(qq)	–	Forty-Second Supplemental Indenture, dated as of February 5, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, providing for the Amendment of Section 1.1 of the Original Indenture. (Filed as Exhibit 4.7(qq) to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.)
*4.4.1(rr)	–	Forty-Third Supplemental Indenture, dated as of August 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008A (Burke) Note, Series 2008B (Burke) Note and Series 2008C (Burke) Note. (Filed as Exhibit 4.7.1(rr) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(ss)	–	Forty-Fourth Supplemental Indenture, dated as of September 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008 (FFB S-8) Note and Series 2008 (RUS S-8) Reimbursement Note. (Filed as Exhibit 4.7.1(ss) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(tt)	–	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2008D (Burke) Note, Series 2008E (Burke) Note, Series 2008F (Burke) Note, Series 2008G (Burke) Note and Series 2008A (Monroe) Note. (Filed as Exhibit 4.7.1(tt) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(uu)	–	Forty-Sixth Supplemental Indenture, dated as of February 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2009 A. (Filed as Exhibit 4.7.1(uu) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(vv)	–	Forty-Seventh Supplemental Indenture, dated as of February 19, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, providing for the Amendment of the Original Indenture. (Filed as Exhibit 4.7.1(vv) to the Registrant's Form 10-K for the fiscal year ended December 31, 2008, File No. 33-7591.)
*4.4.1(ww)	–	Forty-Eighth Supplemental Indenture, dated as of August 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009B CFC Note, Series 2009C CFC Note and Series 2009D CFC Project Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2009, File No. 333-159338.)
*4.4.1(xx)	–	Forty-Ninth Supplemental Indenture, dated as of November 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2009 B. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarter ended September 30, 2009, File No. 333-159338.)
*4.4.1(yy)	–	Fiftieth Supplemental Indenture, dated as of November 30, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009A Line of Credit Notes. (Filed as Exhibit 4.7.1 (yy) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*4.4.1(zz)	–	Fifty-First Supplemental Indenture, dated as of December 1, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2009A (Heard) Note, Series 2009A (Monroe) Note and Series 2009B (Monroe) Note. (Filed as Exhibit 4.7.1 (zz) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)

*4.4.1(aaa)	–	Fifty-Second Supplemental Indenture, dated as of December 30, 2009, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the First Mortgage Bond, Series 2009 CoBank (Clean Renewable Energy Bond). (Filed as Exhibit 4.7.1 (aaa) to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*4.4.1(bbb)	–	Fifty-Third Supplemental Indenture, dated as of March 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010A (Burke) Note, Series 2010B (Burke) Note, Series 2010A (Monroe) Note, Series 2010A (Burke) Reimbursement Obligation, Series 2010B (Burke) Reimbursement Obligation and Series 2010A (Monroe) Reimbursement Obligation. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010, File No. 000-53908.)
*4.4.1(ccc)	–	Fifty-Fourth Supplemental Indenture, dated as of May 21, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, confirming the lien of the Indenture with respect to certain After-Acquired Property (relating to the Hawk Road and Hartwell Energy Facilities). (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2010, File No. 000-53908.)
*4.4.1(ddd)	–	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010 (FFB V-8) Note and Series 2010 (RUS V-8) Reimbursement Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2010, File No. 000-53908.)
*4.4.1(eee)	–	Fifty-Sixth Supplemental Indenture, dated as of November 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2010 A. (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 8, 2010, File No. 000-53908.)
*4.4.1(fff)	–	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2010A CFC Note. (Filed as Exhibit 4.8.1(fff) to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
*4.4.1(ggg)	–	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Agreement Modifying Future Advance Promissory Note. (Filed as Exhibit 4.8.1(ggg) to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
*4.4.1(hhh)	–	Fifty-Ninth Supplemental Indenture, dated as of March 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2011A (Appling) Note, Series 2011A (Burke) Note and Series 2011A (Monroe) Note. (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.4.1(iii)	–	Sixtieth Supplemental Indenture, dated as of April 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2011 (FFB W-8) Note, Series 2011 (RUS W-8) Reimbursement Note, Series 2011 (FFB X-8) Note, and Series 2011 (RUS X-8) Reimbursement Note. (Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.)
*4.4.1(jjj)	–	Sixty-First Supplemental Indenture, dated as of August 1, 2011, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation First Mortgage Bonds, Series 2011A (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2011, File No. 000-53908.)

*4.4.1(kkk)	–	Sixty-Second Supplemental Indenture, dated as of April 1, 2012, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2012A (Monroe) Note (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2012, File No. 000-53908.)
*4.4.1(lll)	–	Sixty-Third Supplemental Indenture, dated as of November 1, 2012, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2012A (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 28, 2012, File No. 000-53908.)
*4.4.1(mmm)	–	Sixty-Fourth Supplemental Indenture, dated as of April 1, 2013, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2013A (Appling) Note, Series 2013A (Burke) Note and Series 2013A (Monroe) Note (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.)
*4.4.1(nnn)	–	Sixty-Fifth Supplemental Indenture, dated as of April 23, 2013, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2013 (FFB Y-8) Note, Series 2013 (RUS Y-8) Reimbursement Note, Series 2013 (FFB AA-8) Note, and Series 2013 (RUS AA-8) Reimbursement Note and amendments to the Indenture. (Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.)
*4.4.1(ooo)	–	Deed to Secure Debt, Security Agreement and Sixty-Sixth Supplemental Indenture, dated as of April 25, 2013, made by Oglethorpe and Murray County Industrial Development Authority to U.S. Bank National Association, as trustee, relating to the consolidation of Murray I and II LLC (Filed as Exhibit 4.4 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.)
*4.4.1(ppp)	–	Sixty-Seventh Supplemental Indenture, dated as of February 20, 2014, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Future Advance Promissory Note No. 1, Reimbursement Note No. 1, Future Advance Promissory Note No. 2, Reimbursement Note No. 2 and amendments to the Indenture (Filed as Exhibit 4.8 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.4.1(qqq)	–	Sixty-Eighth Supplemental Indenture, dated as of June 1, 2014 made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2014A (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on June 11, 2014, File No. 000-53908.)
*4.4.1(rrr)	–	Sixty-Ninth Supplemental Indenture, dated as of September 2, 2014 made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2014 (FFB AB-8) Note and Series 2014 (RUS AB-8) Reimbursement Note (Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2014, File No. 000-53908.)
*4.4.1(sss)	–	Seventieth Supplemental Indenture, dated as of May 27, 2015, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Amendment of the Series 2011 (FFB W-8) Note. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2015, File No. 000-53908.)
*4.4.1(ttt)	–	Seventy-First Supplemental Indenture, dated August 24, 2015, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the addition of property in Walton County, Georgia. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2015, File No. 000-53908.)

*4.4.1(uuu)	–	Seventy-Second Supplemental Indenture, dated as of April 1, 2016, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2016A (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on April 19, 2016, File No. 000-53908).
*4.4.2	–	Security Agreement, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. (Filed as Exhibit 4.8.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*4.5	–	Unsecured Indenture, dated as of December 22, 2010, by and between Oglethorpe and U.S. Bank National Association, as trustee (Filed as Exhibit 4.1 to the Registrant's Form S-3 Registration Statement, File No. 333-171342.)
4.6.1(1)	–	Loan Agreement, dated as of August 1, 2008, 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 2008A, and three other substantially identical (Fixed Rate Bonds) loan agreements.
4.6.2(1)	–	Note, dated August 27, 2008, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of August 1, 2008, between Development Authority of Burke County and U.S. Bank National Association relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2008A, and three other substantially identical notes.
4.6.3(1)	–	Trust Indenture, dated as of August 1, 2008, between Development Authority of Burke County and U.S. Bank National Association, as trustee, relating to Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2008A, and three other substantially identical indentures.
4.7.1(1)	–	Loan Agreement, dated as of December 1, 2009, between Development of Monroe County and Oglethorpe relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical (Variable Rate Bonds) loan agreements.
4.7.2(1)	–	Note, dated December 1, 2009, from Oglethorpe to U.S. Bank National Association , as trustee, pursuant to a Trust Indenture, dated December 1, 2009, between Development Authority of Monroe County and U.S. Bank National Association relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical notes.
4.7.3(1)	–	Trust Indenture, dated December 1, 2009, between Development Authority of Monroe County and U.S. Bank National Association, as trustee, relating to Development Authority of Monroe County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Scherer Project), Series 2009A, and five other substantially identical indentures.
4.8.1(1)	–	Loan Agreement, dated as of April 1, 2013, between the Development Authority of Appling County and Oglethorpe relating to Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical (Term Rate Bonds) loan agreements.

4.8.2[1]	–	Note, dated April 23, 2013, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of April 1, 2013, between the Development Authority of Appling County and U.S. Bank National Association, as trustee, relating to the Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical notes.
4.8.3[1]	–	Trust Indenture, dated as of April 1, 2013, between the Development Authority of Appling County and U.S. Bank National Association, as trustee, relating to the Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical indentures.
4.9.1[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.
4.9.2[1]	–	First Amendment to Term Loan Agreement, dated as of December 20, 2013, by and between Oglethorpe and National Rural Utilities Cooperative Finance Corporation, relating to the Series 2009C Note.
4.9.3[1]	–	Series 2009C CFC Note, dated August 11, 2009, in the original principal amount of $250,000,000, from Oglethorpe to National Rural Utilities Cooperative Finance Corporation.
4.10.1[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).
4.10.2[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.
*4.11.1	–	Note Purchase Agreement, dated February 20, 2014, between Oglethorpe, Federal Financing Bank and United States Department of Energy (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.11.2	–	Future Advance Promissory Note No. 1, dated February 20, 2014, from Oglethorpe to Federal Financing Bank (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.11.3	–	Future Advance Promissory Note No. 2, dated February 20, 2014, from Oglethorpe to Federal Financing Bank (Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.11.4	–	Loan Guarantee Agreement, dated February 20, 2014, between Oglethorpe and the Department of Energy (Filed as Exhibit 4.4 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.11.5	–	Reimbursement Note No. 1, dated February 20, 2014, issued by Oglethorpe to the Department of Energy (Filed as Exhibit 4.5 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*4.11.6	–	Reimbursement Note No. 2, dated February 20, 2014, issued by Oglethorpe to the Department of Energy (Filed as Exhibit 4.6 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)

*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 a 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(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.)

*10.2.1(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.)
*10.2.1(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.)
*10.2.1(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.)
*10.2.1(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.)
*10.2.2(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.)
*10.2.2(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.)
*10.2.2(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.)
*10.2.3	–	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.)
*10.3.1(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.)
*10.3.1(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.)

*10.3.1(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.)
*10.3.2	–	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.)
*10.3.2(a)	–	Amendment No. 1 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement, dated as of April 8, 2008, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (filed as Exhibit 10.3.2(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.3.2(b)	–	Agreement and Amendment No. 2 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement, dated as of February 20, 2014, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (filed as Exhibit 10.3.2(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.3.2(c)	–	Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia and the City of Dalton, Georgia, dated as of February 20, 2014. (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.)
*10.3.3	–	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.)
*10.3.3(a)	–	Amendment No. 1 to Plant Alvin W. Vogtle Nuclear Units Amended and Restated Operating Agreement, dated as of April 8, 2008, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (filed as Exhibit 10.3.3(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.3.3(b)	–	Agreement and Amendment No. 2 to Plant Alvin W. Vogtle Nuclear Units Amended and Restated Operating Agreement, dated as of February 20, 2014, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia. (filed as Exhibit 10.3.3(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
10.3.4(a)(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 & Webster, 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.)

10.3.4(b)[2]	–	Amendment No. 1, dated as of December 11, 2009, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)29 of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2009, filed with the SEC on February 25, 2010.)
10.3.4(c)[2]	–	Amendment No. 2, dated as of January 15, 2010, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(1) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2010, filed with the SEC on May 7, 2010.)
10.3.4(d)[2]	–	Amendment No. 3, dated as of February 23, 2010, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2010, filed with the SEC on May 7, 2010.)
10.3.4(e)[2]	–	Amendment No. 4, dated as of May 2, 2011, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended June 30, 2011, filed with the SEC on August 5, 2011.)
10.3.4(f)[2]	–	Amendment No. 5, dated as of February 7, 2012, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2012, filed with the SEC on May 7, 2012.)
10.3.4(g)[2]	–	Amendment No. 6, dated as of January 23, 2014, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)2 of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2014, filed with the SEC on May 8, 2014.)

10.3.4(h)[2]	–	Amendment No. 7, dated as of December 31, 2015, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(25) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2015, filed with the SEC on February 26, 2016.)
10.3.4(i)[2]	–	Amendment No. 8, dated as of April 20, 2016, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(3) of Georgia Power Company's Form 10-Q for the quarterly period ended June 30, 2016, filed with the SEC on August 8, 2016.)
*10.4.1	–	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.)
*10.4.2(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.)
*10.4.2(b)	–	Amendment to Plant Hal Wansley Operating Agreement, dated as of January 15, 1995, 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.)
10.4.2(c)		Second Amendment to Plant Hal Wansley Operating Agreement, dated as of October 31, 2016, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia.
*10.4.3	–	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.)
*10.5.1	–	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.)
*10.5.2	–	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.)
*10.6.1	–	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.)
*10.6.2	–	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.)

*10.7.1	–	Amended and Restated Wholesale Power Contract, dated as of January 1, 2003, between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 36 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.)
*10.7.2	–	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 scheduling identifying 35 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.)
*10.7.3	–	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 36 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.)
*10.7.4	–	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 36 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.)
*10.7.5	–	Wholesale Power Contract, dated November 1, 2009, between Oglethorpe and Flint Electric Membership Corporation. (Filed as Exhibit 10.8.8 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*10.7.6	–	Supplemental Agreement to the Wholesale Power Contract, dated as of November 1, 2009, by and between Oglethorpe, Flint Electric Membership Corporation and the United States of America. (Filed as Exhibit 10.8.9 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.)
*10.8	–	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.)
*10.9	–	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.)
*10.9(a)	–	Amendment No. 1 to Second Amended and Restated Nuclear Managing Board Agreement, dated as of April 8, 2008, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton. (filed as Exhibit 10.9(a) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)
*10.9(b)	–	Agreement and Amendment No. 2 to Second Amended and Restated Nuclear Managing Board Agreement, dated as of February 20, 2014, among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPV J, LLC, MEAG Power SPV P, LLC, MEAG Power SPV M, LLC and City of Dalton. (filed as Exhibit 10.9(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2013, File No. 000-53908.)

*10.10	–	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 37 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.)
*10.11.1(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.)
*10.11.1(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.)
*10.11.2	–	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.)
*10.11.3	–	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.)
*10.12	–	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.)
*10.13	–	Credit Agreement, dated as of March 23, 2015, among Oglethorpe, as borrower, and the lenders identified therein, including National Rural Utilities Cooperative Finance Corporation, as administrative agent. (Filed as Exhibit 10.13 to the Registrant's Form 10-K for the fiscal year ended December 31, 2015, File No. 000-53908.)
*10.14(a)(3)	–	Employment Agreement, dated as of October 11, 2013, between Oglethorpe and Michael L. Smith. (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed October 16, 2013, File No. 000-53908.)
*10.14(b)(3)	–	Amendment to Employment Agreement, dated March 21, 2016, between Oglethorpe and Michael L. Smith. (Filed as Exhibit 10.14(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 2015, File No. 000-53908.)
10.15(3)	–	Amended and Restated Employment Agreement, dated as of January 1, 2017, between Oglethorpe and Michael W. Price.
10.16(3)	–	Amended and Restated Employment Agreement, dated as of January 1, 2017, between Oglethorpe and Elizabeth B. Higgins.
10.17(3)	–	Amended and Restated Employment Agreement, dated as of January 1, 2017, between Oglethorpe and William F. Ussery.
12.1	–	Oglethorpe Computation of Ratio of Earnings to Fixed Charges, Margins for Interest Ratio and Equity Ratio.
14.1	–	Code of Conduct, available on our website, www.opc.com.
23.1	–	Consent of Ernst & Young LLP
31.1	–	Rule 13a-14(a)/15d-14(a) Certification, by Michael L. 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 Michael L. 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, 2016, File No. 000-53908.)
101	–	XBRL Interactive Data File.

(1) Pursuant to 17 C.F.R. 229.601(b)(4)(iii), this document(s) is not filed herewith; however the registrant hereby agrees that such document(s) will be provided to the Commission upon request.

(2) Confidential treatment has been requested for certain confidential portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934. In accordance with Rule 24b-2, these confidential portions have been omitted from this exhibit and filed separately with the SEC.

(3) Indicates a management contract or compensatory arrangement required to be filed as an exhibit to this Report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of March, 2017.

OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION)

By: /s/ MICHAEL L. SMITH

MICHAEL L. 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/ MICHAEL L. SMITH MICHAEL L. SMITH	President and Chief Executive Officer (Principal Executive Officer)	March 27, 2017
/s/ ELIZABETH B. HIGGINS ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 27, 2017
/s/ G. KENNETH WARREN, JR. G. KENNETH WARREN, JR.	Vice President, Controller (Principal Accounting Officer)	March 27, 2017
/s/ JIMMY G. BAILEY JIMMY G. BAILEY	Director	March 27, 2017
/s/ RANDY CRENSHAW RANDY CRENSHAW	Director	March 27, 2017
/s/ WM. RONALD DUFFEY WM. RONALD DUFFEY	Director	March 27, 2017
/s/ M. ANTHONY HAM M. ANTHONY HAM	Director	March 27, 2017
/s/ ERNEST A. JAKINS III ERNEST A. JAKINS III	Director	March 27, 2017

Signature	Title	Date
/s/ FRED MCWHORTER FRED MCWHORTER	Director	March 27, 2017
/s/ MARSHALL S. MILLWOOD MARSHALL S. MILLWOOD	Director	March 27, 2017
/s/ JEFFREY W. MURPHY JEFFREY W. MURPHY	Director	March 27, 2017
/s/ DANNY L. NICHOLS DANNY L. NICHOLS	Director	March 27, 2017
/s/ SAMMY G. SIMONTON SAMMY G. SIMONTON	Director	March 27, 2017
/s/ BOBBY C. SMITH, JR. BOBBY C. SMITH, JR.	Director	March 27, 2017
/s/ GEORGE L. WEAVER GEORGE L. WEAVER	Director	March 27, 2017
/s/ JAMES I. WHITE JAMES I. WHITE	Director	March 27, 2017