

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-4
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Oglethorpe Power Corporation
(An Electric Membership Corporation)

(Exact name of registrant as specified in its charter)

Georgia
(State of incorporation)

4911

(Primary Standard Industrial
Classification Code Number)

2100 East Exchange Place
Tucker, Georgia 30084-5336
(770) 270-7600

(Address and telephone number of
registrant's principal executive offices)

58-1211925

(I.R.S. Employer
Identification Number)**Elizabeth B. Higgins****Executive Vice President and Chief Financial Officer****Oglethorpe Power Corporation**

2100 East Exchange Place
Tucker, Georgia 30084-5336
(770) 270-7600

(Name, address and telephone number
of agent for service)

Copies to:

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Approximate date of commencement of proposed sale of the securities to the public: As soon as practicable after the registration statement becomes effective.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box.

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

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

Large accelerated filer Non-accelerated filer Accelerated filer Smaller reporting company Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act.

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Tender Offer) Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer)

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act or until this registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to Section 8(a), may determine.

The information in this prospectus is not complete and may be changed. We may not complete the exchange offers and issue these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED APRIL 2, 2025

PRELIMINARY PROSPECTUS



Offers To Exchange

\$350,000,000

**Registered 5.800% Green First Mortgage Bonds, Series 2024A due 2054
for any and all**

Unregistered 5.800% Green First Mortgage Bonds, Series 2024A due 2054

and

\$350,000,000

**Registered 5.900% Green First Mortgage Bonds, Series 2025A due 2055
for any and all**

Unregistered 5.900% Green First Mortgage Bonds, Series 2025A due 2055

We are offering to exchange up to (i) \$350,000,000 aggregate principal amount of our registered 5.800% Green First Mortgage Bonds, Series 2024A due 2054 (the "2024A Exchange Bonds"), for \$350,000,000 aggregate principal amount of our outstanding unregistered 5.800% Green First Mortgage Bonds, Series 2024A due 2054 (the "2024A Original Bonds") and (ii) \$350,000,000 aggregate principal amount of our registered 5.900% Green First Mortgage Bonds, Series 2025A due 2055 (the "2025A Exchange Bonds" and together with the 2024A Exchange Bonds, the "Exchange Bonds"), for \$350,000,000 aggregate principal amount of our outstanding unregistered 5.900% Green First Mortgage Bonds, Series 2025A due 2055 (the "2025A Original Bonds" and together with the 2024A Original Bonds, the "Original Bonds").

Each exchange offer is subject to customary closing conditions and will expire at 5:00 p.m., New York City time, on _____, 2025, unless we extend one or both exchange offers in our sole discretion.

The Exchange Offers

- All Original Bonds that are validly tendered, and not validly withdrawn, will be exchanged for an equal principal amount of the corresponding series of Exchange Bonds. You should carefully review the procedures for tendering the Original Bonds beginning on page 104.
- You may validly withdraw tenders of Original Bonds at any time before the expiration of the applicable exchange offer.
- The terms of the Exchange Bonds to be issued in the exchange offers are substantially identical to the Original Bonds, except that the Exchange Bonds will be registered under the Securities Act, and will not have any transfer restrictions, registration rights or additional interest provisions.
- We issued the Original Bonds in transactions not requiring registration under the Securities Act and, as a result, their transfer is restricted. We are making the exchange offers to satisfy your registration rights as a holder of the Original Bonds.
- The exchange of the Original Bonds for the Exchange Bonds will not be a taxable transaction for United States federal income tax purposes, but you should see the discussion under "SUMMARY OF MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES" for more information.
- We will not receive any proceeds from the exchange offers.
- No public market currently exists for the Exchange Bonds. We do not intend to apply for listing of the Exchange Bonds on any national securities exchange or to arrange for the Exchange Bonds to be quoted on any automated quotation system, and, therefore, an active public market for the Exchange Bonds is not anticipated.
- Neither of the exchange offers is conditioned on the consummation of the other exchange offer.

The Exchange Bonds will be secured by a first mortgage lien on substantially all of our owned tangible and certain of our intangible property equally and ratably with all our other obligations issued under the first mortgage indenture described in this prospectus, subject to certain exceptions and exclusions as described or referred to in this prospectus. See "SUMMARY OF THE FIRST MORTGAGE INDENTURE—Security for Payment."

All untendered Original Bonds will remain outstanding and continue to be subject to the transfer restrictions set forth in the Original Bonds and in the indenture governing the Original Bonds. In general, the Original Bonds may not be offered or sold, unless registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. Other than in connection with the exchange offers, we do not currently anticipate that we will register the Original Bonds under the Securities Act.

Each broker-dealer that receives Exchange Bonds for its own account pursuant to the exchange offers must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of those Exchange Bonds. The letter of transmittal accompanying this prospectus states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Bonds received in exchange for Original Bonds the broker-dealer acquired as a result of market-making activities or trading activities. We have agreed that we will make this prospectus available to any broker-dealer for use in connection with any such resale for a period of 180 days following the expiration date of the applicable exchange offer or such time as such broker-dealers no longer own any Original Bonds. See "PLAN OF DISTRIBUTION."

See "[RISK FACTORS](#)" beginning on page [13](#) for a discussion of factors that you should consider before participating in the exchange offer.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is _____, 2025.

We have not authorized any person to provide any information or to make any representation other than the information contained in this prospectus. If any person provides you any other information or makes any other representation, that information or representation must not be relied upon as having been authorized by us. If you receive any other information, you should not rely on it. We are not making the exchange offers to, nor will we accept surrenders for exchange from, holders of outstanding Original Bonds in any jurisdiction in which the exchange offers would not be in compliance with the securities or blue sky laws of such jurisdiction or where it is otherwise unlawful. This prospectus may only be used where it is legal to sell these securities. You should assume that the information contained in this prospectus is accurate only as of its date. Our business, financial condition, results of operations and prospects may have changed since that date.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This prospectus 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 future capital expenditures, business strategy, regulatory actions, 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 “RISK FACTORS” and in other sections of this prospectus. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this prospectus may not occur.

Any forward-looking statement speaks only as of the date of this prospectus, 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, such as our two new natural gas-fired generation facilities, our battery storage resources, the closure of coal ash ponds and any other future generation projects we may undertake;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- the impact of regulatory or legislative responses to climate change initiatives or efforts to reduce greenhouse gas emissions, including carbon dioxide;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- 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;
- the continued availability of funding from the Rural Utilities Service and the availability of funding under any federal loan or grant programs for which we received awards and our ability to meet the applicable loan or grant conditions and requirements;
- increasing debt caused by significant capital expenditures;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- actions by credit rating agencies;
- commercial banking and financial market conditions;
- the impact of rapid load growth in our members’ service territories and decisions regarding the development of additional generation resources to meet the additional demand;
- risks and regulatory requirements related to the ownership of nuclear facilities;

- adequate funding of our nuclear and coal ash pond decommissioning 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;
- the direct or indirect effect on our business resulting from cyber or physical attacks on us, our members or third-party service providers, vendors or contractors;
- 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;
- the inability of counterparties to meet their obligations to us or our members, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- our members' ability to offer their residential, commercial and industrial customers competitive rates;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption (including from data centers and other large commercial and industrial loads), energy conservation and efficiency efforts and the general economy;
- general economic conditions;
- tariffs and geopolitical trade tensions;
- weather conditions and other natural phenomena;
- litigation or legal and administrative proceedings and settlements;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- early retirement of our co-owned coal units;
- acts of sabotage, wars or terrorist activities, including cyber attacks;
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards;
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events, or similar occurrences;
- significant changes in critical accounting policies material to us; and
- other factors discussed elsewhere in this prospectus.

PROSPECTUS SUMMARY

This summary highlights selected information about us and the exchange offers appearing elsewhere in this prospectus. This summary is not complete and does not contain all of the information that may be important to you and that you should consider before participating in the exchange offer. For a more complete understanding of us and the exchange offers, you should carefully read this prospectus in its entirety.

OUR COMPANY

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 (“kWh”) sales to members and, through our members, consumers served. We are also the second largest power supplier in the state of Georgia.

Our members are local consumer-owned distribution cooperatives providing 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 2.2 million electric consumers (meters) representing approximately 4.7 million people.

Our principal executive offices are located at 2100 East Exchange Place, Tucker, Georgia 30084-5336. Our telephone number is (770) 270-7600. We maintain a website at www.opc.com. Information contained on this website is not incorporated by reference into this prospectus and information contained on this website should not be considered to be part of this prospectus.

Cooperative Principles

We are organized and operate as a cooperative. A cooperative is a business organization owned by its members, which also are its customers. Cooperatives are created to provide goods or services to their members on a not-for-profit basis.

Power Supply Business

We provide wholesale electric service to our members for a significant portion of their aggregate requirements primarily from our fleet of generation assets but also with power purchased from other power suppliers from time to time. In 2024, we supplied energy that accounted for approximately 70% of the retail energy requirements of our members. We provide this service pursuant to long-term, take-or-pay wholesale power contracts with each member. The wholesale power contracts, which extend beyond the final maturity date of the Exchange Bonds, 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.

As of December 31, 2024, our fleet of generating units totaled 9,323 megawatts of summer planning reserve capacity, which includes 729 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. We also supply financial and management services to support Green Power EMC’s purchase of energy from 820 megawatts of renewable resources, including, low-impact hydroelectric, landfill gas and solar facilities.

In 2024, one of our members, Jackson EMC, accounted for approximately 18% of our total revenues, respectively. Each of our other members accounted for less than 10% of our total revenues in 2024.

Agreements with Members

The wholesale power contracts we have with each member are substantially similar and extend through December 31, 2085 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 resource is completed, delayed, terminated, operable, operating, retired, sold, leased, transferred 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 resources, although not all members participate in all resources. For any future generation or purchased power resources, 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 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, whether or not that member has elected to participate in the resource. In the event a member defaults on all or a portion of its payment obligation, the default amount is shared first among the participating members in each resource in which the defaulting member participates. If all these 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.

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.

We have an agreement with our members that requires member approval for us to undertake certain activities. It does not limit our ability to own, manage, control and operate our resources or perform our functions under the wholesale power contracts.

In this regard, we may not provide services unrelated to our resources or our functions under the wholesale power contracts if such 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 service to a member so long as: (i) doing so would not create a conflict of interest with respect to other members, (ii) such service is being provided to all members, or (iii) such service has received the three-part 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 formula 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 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.

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 (as defined herein) 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. Currently, our rates are not subject to the approval of any other federal or state agency or authority, including the Georgia Public Service Commission.

Our Members

Our members, listed on page 43 of this prospectus, include 38 of the 41 electric distribution cooperatives in the State of Georgia.

Our members serve approximately 2.2 million electric consumers (meters) representing approximately 4.7 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. Sales by our members in 2024 amounted to approximately 44.2 million megawatt hours ("MWh"). Historically, our member's 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.

SUMMARY OF THE EXCHANGE OFFERS

On June 21, 2024, we completed a private offering of \$350,000,000 aggregate principal amount of 5.800% Green First Mortgage Bonds, Series 2024A due 2054 and, on January 27, 2025, we completed a private offering of \$350,000,000 aggregate principal amount of 5.900% Green First Mortgage Bonds, Series 2025A due 2055. As part of each offering, we entered into a registration rights agreement with the initial purchasers of each series of Original Bonds in which we agreed to use commercially reasonable efforts to complete an exchange offer for such Original Bonds in compliance with applicable securities laws. See “THE EXCHANGE OFFERS—General; Purpose of the Exchange Offers.”

The following is a brief summary of certain terms of the exchange offers and the principal terms of the Exchange Bonds. It may not contain all the information that is important to you. For additional information regarding the exchange offers and the Exchange Bonds, see “THE EXCHANGE OFFERS” and “DESCRIPTION OF THE EXCHANGE BONDS.”

Original Bonds \$350,000,000 aggregate principal amount of 5.800% Green First Mortgage Bonds, Series 2024A due 2054.

\$350,000,000 aggregate principal amount of 5.900% Green First Mortgage Bonds, Series 2025A due 2055.

Exchange Bonds \$350,000,000 aggregate principal amount of 5.800% Green First Mortgage Bonds, Series 2024A due 2054.

\$350,000,000 aggregate principal amount of 5.900% Green First Mortgage Bonds, Series 2025A due 2055.

The Exchange Bonds have been registered under the Securities Act.

The form and terms of the 2024A Exchange Bonds are identical in all material respects to those of the 2024A Original Bonds, and the form and terms of the 2025A Exchange Bonds are identical in all material respects to those of the 2025A Original Bonds, except, in each case, that the transfer restrictions, registration rights and additional interest provisions relating to the Original Bonds do not apply to the Exchange Bonds.

In addition, the Exchange Bonds will bear a different CUSIP number than the Original Bonds.

The Exchange Offers We are offering to exchange up to \$350,000,000 aggregate principal amount of 2024A Original Bonds for a like aggregate principal amount of the 2024A Exchange Bonds, and \$350,000,000 aggregate principal amount of 2025A Original Bonds for a like aggregate principal amount of the 2025A Exchange Bonds, in each case to satisfy certain of our obligations under the respective registration rights agreement that we entered into when we issued each series of Original Bonds in reliance upon exemptions from registration under the Securities Act.

The Original Bonds may only be tendered in minimum denominations of \$2,000 or in integral multiples of \$1,000 in excess thereof. See “[THE EXCHANGE OFFERS—Terms of the Exchange Offers.](#)”

In order to exchange the Original Bonds, you must follow the required procedures and we must accept the Original Bonds for exchange. We will exchange all Original Bonds validly tendered and not validly withdrawn prior to the expiration date of the applicable exchange offer. See “[THE EXCHANGE OFFERS.](#)”

Expiration Date The exchange offers will expire at 5:00 p.m., New York City time, on _____, 2025, unless we extend one or both exchange offers in our sole discretion.

Tenders

By tendering your Original Bonds, you represent to us that:

- you are acquiring the Exchange Bonds in the ordinary course of your business;
- you are not participating and have no arrangement or understanding with any person to participate in the distribution, as defined in the Securities Act, of the Exchange Bonds;
- you are not our “affiliate,” as defined in Rule 405 under the Securities Act; and
- if you are a broker-dealer that will receive Exchange Bonds for your own account in exchange for Original Bonds that were acquired as a result of market-making or other trading activities, you will deliver a prospectus (or, to the extent permitted by law, make available a prospectus to purchasers) in connection with any resale of such Exchange Bonds. For further information regarding resales of the Exchange Bonds by participating broker-dealers, see the discussion under the caption “[PLAN OF DISTRIBUTION.](#)”

Conditions to the Exchange Offers

The exchange offers are subject to customary conditions, which we may waive. The exchange offers are not conditioned upon the tender of any minimum principal amount of outstanding Original Bonds. Neither of the exchange offers is conditioned on consummation of the other exchange offer. See “[THE EXCHANGE OFFERS—Conditions to the Exchange Offers.](#)”

Procedures for Tendering

You must do one of the following on or prior to the expiration or termination of the applicable exchange offer to participate in that exchange offer:

- tender your Original Bonds using the book-entry transfer procedures described below and sending a properly completed and duly executed letter of transmittal, with any required signature guarantees, or causing to be delivered an agent’s message instead of the letter of transmittal, to the exchange agent. In order for a book-entry transfer to constitute a valid tender of your Original Bonds in the exchange offer, U.S. Bank Trust Company, National Association, as exchange agent, must receive a confirmation of book-entry transfer of your Original Bonds into the exchange agent’s account at The Depository Trust Company (“DTC”) prior to the expiration or termination of the applicable exchange offer. For more information regarding the use of book-entry transfer procedures, including a description of the required agent’s message, see the discussion below under “[THE EXCHANGE OFFERS—Book-Entry Transfers](#)” or
- tender your Original Bonds by sending the certificates for your Original Bonds, in proper form for transfer, a properly completed and duly executed letter of transmittal, with any required signature guarantees, and all other documents required by the letter of transmittal, to U.S. Bank Trust Company, as exchange agent, at one of the addresses listed below under the caption “[THE EXCHANGE OFFERS—Exchange Agent.](#)”

For more information on the procedures for tendering the Original Bonds, see the discussion under the caption “[THE EXCHANGE OFFERS—Procedures for Tendering Original Bonds.](#)”

Special Procedures for Beneficial Owners

If you are a beneficial owner whose Original Bonds are registered in the name of the broker, dealer, commercial bank, trust company or other nominee, and you wish to tender your Original Bonds in the exchange offers, you should promptly contact the person in whose name the Original Bonds are registered and instruct that person to tender on your behalf. Any registered holder that is a participant in DTC's book-entry transfer facility system may make book-entry delivery of the Original Bonds by causing DTC to transfer the Original Bonds into the exchange agent's account. If you wish to tender your Original Bonds in the exchange offers on your own behalf, prior to completing and executing the letter of transmittal and delivering your Original Bonds, you must either make appropriate arrangements to register ownership of the Original Bonds in your name with DTC or obtain a properly completed note power from the person in whose name the Original Bonds are registered.

Guaranteed Delivery Procedures

If you wish to tender your Original Bonds and your Original Bonds are not immediately available, or you cannot deliver your Original Bonds, the letter of transmittal or any other required documents, or you cannot comply with the procedures under DTC's automated tender offer program for transfer of book-entry interests prior to the expiration date, you must tender your Original Bonds according to the guaranteed delivery procedures set forth in this prospectus under "[THE EXCHANGE OFFERS—Guaranteed Delivery Procedures.](#)"

Use of Proceeds

We will not receive any cash proceeds from the exchange offers.

Exchange Agent

U.S. Bank Trust Company, National Association is the exchange agent for the exchange offers. You can find the exchange agent's address, telephone number and e-mail address under the caption "[THE EXCHANGE OFFERS—Exchange Agent.](#)" U.S. Bank Trust Company is also the trustee under the first mortgage indenture governing the Original Bonds and Exchange Bonds.

Resales

Based on interpretations by the SEC staff, as detailed in a series of no-action letters issued to third parties, we believe that the Exchange Bonds issued in the exchange offers pursuant to this prospectus may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery requirements of the Securities Act, provided that:

- any Exchange Bonds you receive will be acquired in the ordinary course of your business;
- you are not participating and have no arrangement or understanding with any person to participate in the distribution, as defined in the Securities Act of the Exchange Bonds; and
- you are not our "affiliate," as defined in Rule 405 under the Securities Act.

We base our belief on interpretations by the SEC staff in no-action letters issued to other issuers making exchange offers similar to ours. We cannot guarantee the SEC would make a similar decision about our exchange offers. If our belief is wrong, you could incur liability under the Securities Act. We will not indemnify or otherwise protect you against any loss incurred as a result of this liability under the Securities Act.

If you are an "affiliate" of ours or are participating or have an arrangement or understanding with any person to participate in the distribution of the Exchange Bonds:

- you cannot rely on the applicable interpretations of the SEC staff;

- you will not be entitled to participate in the exchange offers; and
- you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction of the Exchange Bonds.

See “[THE EXCHANGE OFFERS—Consequences of Failure to Exchange](#)” for more information.

Broker-Dealer

Each broker or dealer that receives Exchange Bonds for its own account in exchange for Original Bonds that were acquired as a result of market-making or other trading activities must acknowledge that it will comply with the registration and prospectus delivery requirements of the Securities Act in connection with any offer to resell or other transfer of the Exchange Bonds issued in the exchange offers, including the delivery of a prospectus that contains information with respect to any selling holder required by the Securities Act in connection with any resale of the Exchange Bonds.

Furthermore, any broker-dealer that acquired any of its Original Bonds directly from us:

- may not rely on the applicable interpretation of the SEC staff’s position contained in *Exxon Capital Holdings Corp.*, SEC no-action letter (April 13, 1988), *Morgan, Stanley & Co. Inc.*, SEC no-action letter (June 5, 1991) and *Shearman & Sterling*, SEC no-action letter (July 2, 1993); and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the Exchange Bonds received in exchange for the Original Bonds where such Original Bonds were acquired by such broker-dealer as a result of market-making activities or other trading activities. Under the registration rights agreements, we have agreed to make available a prospectus in conformity in all material respects with the requirements of the Securities Act, to any participating broker-dealer for use in connection with any resale of any Exchange Bonds acquired in one of the exchange offers for the period beginning when the Exchange Bonds are first issued in the relevant exchange offer and ending upon the earlier of the expiration of the 180th day after that exchange offer has been completed or such time as such broker-dealers no longer own any Original Bonds. See “[PLAN OF DISTRIBUTION.](#)”

Registration Rights Agreements

When we issued the 2024A Original Bonds on June 21, 2024, we entered into an exchange and registration rights agreement with RBC Capital Markets, LLC, as representative of the initial purchasers of those bonds. When we issued the 2025A Original Bonds on January 27, 2025, we entered into an exchange and registration rights agreement with J.P. Morgan Securities LLC, as representative of the initial purchasers of those bonds. Pursuant to these registration rights agreements we agreed, for the benefit of the holders of the Original Bonds, at our cost, to:

- file, not later than 300 days after the issue date of the 2024A Original Bonds, and not later than 180 days after the issue date of the 2025A Original Bonds, a registration statement with respect to a registered offer to exchange the Original Bonds for the Exchange Bonds;

- use commercially reasonable efforts to cause the exchange offer registration statement to be declared effective under the Securities Act within 390 days after the issue date of the 2024A Original Bonds, and within 270 days after the issue date of the 2025A Original Bonds; and
- complete the relevant exchange offer within 60 business days from the date the exchange offer registration statement is declared effective.

If we do not meet the applicable deadlines in the preceding sentence, or if we fail to meet certain other conditions described in the registration rights agreements, each, a “registration default,” the interest rate borne by that series of Original Bonds will increase at a rate of 0.25% per annum for the first 90-day period immediately following the occurrence of the registration default and at a rate of 0.50% per annum for the remaining portion of the registration default.

Under some circumstances set forth in the registration rights agreements, holders of the Original Bonds, including holders who are not permitted to participate in the exchange offers, may require us to file, and cause to become effective, a shelf registration statement covering resales of the Original Bonds by these holders.

Copies of the registration rights agreements are incorporated by reference as exhibits to the registration statement of which this prospectus forms a part. See “[THE EXCHANGE OFFERS—General; Purpose of the Exchange Offers.](#)”

Consequences of Failure to Exchange

Original Bonds that are not tendered or that are tendered but not accepted will, following the completion of the exchange offers, be returned to the tendering holder, remain outstanding and continue to be subject to their existing terms. See “[RISK FACTORS](#)” and “[THE EXCHANGE OFFERS—Terms of the Exchange Offers.](#)” Following the completion of the exchange offers, we will have no obligation to exchange Original Bonds for Exchange Bonds.

Material Tax Considerations

The trading market for Original Bonds not exchanged in the exchange offers may be more limited than it is at present. Therefore, if your Original Bonds are not tendered and accepted in the exchange offers, it may become more difficult for you to sell or transfer your unexchanged Original Bonds.

The exchange of Original Bonds for Exchange Bonds pursuant to the exchange offers generally will not be a taxable event for U.S. federal income tax purposes. You should consult your own tax advisor to determine the U.S. federal, state and other tax consequences of the exchange of the Original Bonds for the Exchange Bonds. See “[SUMMARY OF MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES.](#)”

Risk Factors

See “[RISK FACTORS](#)” for a discussion of factors that should be considered before exchanging the Original Bonds in the exchange offers.

SUMMARY OF THE EXCHANGE BONDS

Issuer	Oglethorpe Power Corporation (An Electric Membership Corporation)
Securities Offered	<p>\$350,000,000 aggregate principal amount of 5.800% Green First Mortgage Bonds, Series 2024A due 2054.</p> <p>\$350,000,000 aggregate principal amount of 5.900% Green First Mortgage Bonds, Series 2025A due 2055.</p>
Maturity Dates	<p>June 1, 2054 for the 2024A Exchange Bonds</p> <p>February 1, 2055 for the 2025A Exchange Bonds</p>
Form and Denominations	The Exchange Bonds of each series will be represented by global certificates deposited with, or on behalf of, DTC or its nominee. The Exchange Bonds will be issued in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof.
Interest Payment Dates	Interest on the Exchange Bonds will accrue from the last date on which interest was paid on the applicable series of Original Bonds surrendered in the exchange offers or, if no interest has been paid, from the issuance date. We will pay interest on the 2024A Exchange Bonds semi-annually in arrears on June 1 and December 1 and on the 2025A Exchange Bonds semi-annually in arrears on February 1 and August 1.
Optional Redemption	<p>For the 2024A Exchange Bonds, at any time or from time to time before December 1, 2053, we may redeem the 2024A Exchange Bonds, in whole or in part at a “make whole” redemption price equal to the greater of:</p> <ul style="list-style-type: none">• 100% of the principal amount of the 2024A Exchange Bonds being redeemed; and• the sum of the present values of the remaining principal and interest payments on the 2024A Exchange Bonds being redeemed that would be due if such Exchange Bonds matured on December 1, 2053 (excluding interest accrued and unpaid through the redemption date), discounted at a rate equal to the sum of (i) the yield to maturity of the U.S. Treasury security having a life (assuming for this purpose that the 2024A Exchange Bonds matured on December 1, 2053) equal to, or the average yield to maturity of two U.S. Treasury securities closely corresponding to, the remaining average life of the 2024A Exchange Bonds being redeemed and trading in the secondary market at the price closest to par, and (ii) 25 basis points. <p>plus, in each case, accrued and unpaid interest through the redemption date.</p> <p>At any time or from time to time on or after December 1, 2053, we may redeem the 2024A Exchange Bonds, in whole or in part at a redemption price equal to 100% of the principal amount of the 2024A Exchange Bonds being redeemed, plus accrued and unpaid interest thereon to, but excluding, the redemption date.</p> <p>For the 2025A Exchange Bonds, at any time or from time to time before August 1, 2054, we may redeem the 2025A Exchange Bonds, in whole or in part at a “make whole” redemption price equal to the greater of:</p> <ul style="list-style-type: none">• 100% of the principal amount of the 2025A Exchange Bonds being redeemed; and

- the sum of the present values of the remaining principal and interest payments on the 2025A Exchange Bonds being redeemed that would be due if such Exchange Bonds matured on August 1, 2054 (excluding interest accrued and unpaid through the redemption date), discounted at a rate equal to the sum of (i) the yield to maturity of the U.S. Treasury security having a life (assuming for this purpose that the 2025A Exchange Bonds matured on August 1, 2054) equal to, or the average yield to maturity of two U.S. Treasury securities closely corresponding to, the remaining average life of the 2025A Exchange Bonds being redeemed and trading in the secondary market at the price closest to par, and (ii) 20 basis points.

plus, in each case, accrued and unpaid interest through the redemption date.

At any time or from time to time on or after August 1, 2054, we may redeem the 2025A Exchange Bonds, in whole or in part at a redemption price equal to 100% of the principal amount of the 2025A Exchange Bonds being redeemed, plus accrued and unpaid interest thereon to, but excluding, the redemption date.

See “[DESCRIPTION OF THE EXCHANGE BONDS—Redemption Provisions.](#)”

First Mortgage Indenture

We will issue the Exchange Bonds under our Indenture dated March 1, 1997, made by Oglethorpe to the predecessor of U.S. Bank Trust Company, National Association (the “trustee”), as amended and supplemented (the “first mortgage indenture”). The first mortgage indenture constitutes a first priority lien on substantially all of our owned tangible and certain of our intangible property equally and ratably with all other obligations issued under the first mortgage indenture. As of December 31, 2024, we had approximately \$12.4 billion of secured indebtedness outstanding under the first mortgage indenture. See “[SUMMARY OF THE FIRST MORTGAGE INDENTURE.](#)”

Use of Proceeds

We will not receive any cash proceeds from the issuance of the Exchange Bonds. In consideration for issuing the Exchange Bonds as contemplated in this prospectus, we will receive in exchange Original Bonds in like principal amount, which will be cancelled and, as such, the issuing the Exchange Bonds will not result in any change to our capitalization.

Second Party Opinion

In connection with the initial issuance of each series of Original Bonds, an independent second party opinion provider evaluated the intended use of proceeds and determined that each series of Original Bonds was in conformance with the four core components of the ICMA Green Bond Principles (the “Second Party Opinions”).

DTC Eligibility

The Exchange Bonds will be issued in fully registered form and will be represented by one or more global bonds, without coupons, deposited with DTC and registered in the name of Cede & Co., as its nominee. Beneficial interests in the global bonds will trade in DTC’s Same Day Funds Settlement System and secondary market trading activity in these beneficial interests will therefore settle in immediately available funds. Subject to some exceptions, beneficial interests in the Exchange Bonds will be shown on, and transfers will be effected only through, records maintained by DTC and its direct and indirect participants.

No Public Market

We do not intend to list the Exchange Bonds on any securities exchange or have them quoted on any automated quotation system. If issued, the Exchange Bonds generally will be freely transferable but will also be new securities for which there will not initially be a market. We cannot assure you that any trading market for the Exchange Bonds will develop upon completion of the exchange offers or, if such market does develop, that such market will be maintained or as to the liquidity of any market for the Exchange Bonds. As a result, there may not be a secondary market for the Exchange Bonds. See “[PLAN OF DISTRIBUTION](#).”

Trustee

U.S. Bank Trust Company, National Association.

Governing Law

The first mortgage indenture and the Exchange Bonds will be governed by and construed in accordance with the laws of the State of Georgia.

Risk Factors

Certain risks could affect the payments to be made with respect to the Exchange Bonds or the market value of the Exchange Bonds. See “[RISK FACTORS](#)” beginning on page [13](#) of this prospectus for a discussion of such risks. Such discussion is not exhaustive, should be read in conjunction with all other parts of this prospectus and should not be considered as a complete description of all risks that could affect such payments or the market value of the Exchange Bonds. You should analyze carefully the information contained in this prospectus and additional information in the form of the complete documents summarized herein, copies of which are available as described in prospectus. See “[AVAILABLE INFORMATION](#).”

SUMMARY OF THE FIRST MORTGAGE INDENTURE

Security for the Exchange Bonds	<p>The Exchange Bonds will be secured equally and ratably with all other obligations issued under the first mortgage indenture by 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 that relate to the ownership, operation or maintenance of electric generation facilities owned by us, but excluding excepted property and excludable property as set forth in the first mortgage indenture. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE.”</p>
Rate Covenant	<p>The first mortgage indenture obligates us to establish and collect rates for the use or the sale of the output, capacity or service of our properties that produce money sufficient, together with other money available to us, to enable us to comply with all covenants under the first mortgage indenture and, subject to any necessary regulatory approvals, which are reasonably expected, together with our other revenues, to yield a margins for interest ratio (as defined herein) equal to at least 1.10 for each fiscal year. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE—Covenants—Rate Covenant.” For 2025, our board of directors approved a budget to achieve a 1.10 margins for interest ratio.</p>
Additional Obligations	<p>As long as we are in compliance with the minimum margins for interest ratio required by the first mortgage indenture, we may issue additional obligations under the first mortgage indenture. The amount of obligations we may issue is based on the bondable value of specified property additions and retirements we have made, the aggregate principal amount of first mortgage indenture obligations we have retired or defeased, and deposits of cash and certain securities we have made with the trustee, among other things. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE—Additional Obligations.”</p>
Limitation on Distributions to Members	<p>The first mortgage indenture prohibits us from making any distribution, payment or retirement of patronage capital to our members if, at the time thereof or after giving effect thereto:</p> <ul style="list-style-type: none">• an event of default exists under the first mortgage indenture;• our aggregate margins and equities as of the end of the most recent fiscal quarter would be less than 20% of our total long-term debt and equities at such time; or• the aggregate amount expended for the distribution, payment or retirement on or after the date on which our aggregate margins and equities first reach 20% of our total long-term debt and equities would exceed 35% of our aggregate net margins earned after that date. <p>The restrictions set forth in the second and third bullet points above, however, would not apply if, after giving effect to the distribution, payment or retirement, our aggregate margins and equities as of the end of the most recent fiscal quarter would not be less than 30% of our total long-term debt and equities. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE—Covenants—Limitation on Distributions, Payments or Retirement of Patronage Capital.”</p>

RISK FACTORS

You should carefully consider the risk factors set forth below as well as the other information contained in this prospectus before deciding to tender your Original Bonds in the exchange offers. Any of the following risks could materially and adversely affect our business, financial condition, operating results or cash flow; however, the following risks are not our only risks. Additional risks and uncertainties not currently known to us or those we currently view to be immaterial may also materially and adversely affect our business, financial condition, results of operations or cash flow. If any known or unknown risk materially affects our business, financial condition, results of operations or cash flow, the trading price of the Exchange Bonds could decline or we may not be able to make payments of interest and principal on the Exchange Bonds, and you may lose all or part of your original investment.

Facility Ownership, Operation and Construction Risk Factors

We are subject to construction risks for additional projects we are undertaking to meet projected load growth in Georgia.

As a result of projected load growth in Georgia, we and our members have approved the development and construction of two new natural gas-fired generation resources. One of the projects is an approximately 1,425-megawatt, two-unit combined cycle generation facility to be located on land we own adjacent to the Smarr Energy Facility in Monroe County, Georgia. Our preliminary cost estimate for this facility is approximately \$1.8 billion to \$2.3 billion and the projected commercial operation date is 2029. The other project is an approximately 240-megawatt combustion turbine unit to be constructed at our Talbot Energy Facility. Our preliminary cost estimate for this unit is approximately \$360 million and the projected commercial operation date is 2029. In connection with these additional resources, we entered into agreements to provide firm capacity on new natural gas pipeline infrastructure to meet our anticipated fuel supply needs. We and our members have also approved 75 megawatts of utility-scale battery storage resources in connection with an \$81 million award under the Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program, and the projected commercial operation dates are in 2029 and 2030. Our cost estimate of these battery storage resources is approximately \$200 million to \$250 million, before the application of any grant proceeds. We and our members may also continue to consider additional generation resources in the future.

Our development and construction of new generating resources and the construction of new natural gas pipeline infrastructure capacity by third parties to serve these resources is subject to construction risk. We will also be subject to construction risks for capital projects to comply with current or future environmental standards. Many factors could lead to cost increases and schedule delays for any of these projects, including:

- challenges related to contractors or vendors, including generation equipment manufacturers;
- contractor and subcontractor performance;
- cost and availability of labor;
- timing and issuance of necessary permits or approvals (including required certificates from regulatory agencies) and any related litigation;
- shortages, delays, increased costs or inconsistent quality of materials and equipment, including the potential impact of any tariffs;
- performance under construction and equipment agreements and contract disputes;
- the cost and availability of debt financing, including the availability of federal loan or grant programs, increased interest rates or increased funding costs as a result of construction schedule delays;
- catastrophic events, natural disasters and future pandemic health events; and
- weather conditions.

Failure to complete any construction project on schedule and on budget for any reason could 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.

We own nuclear facilities which give rise to environmental, regulatory, financial, operational and other risks.

We own a 30% undivided interest in each of the Plant Hatch and Plant Vogtle nuclear generating facilities. Collectively, our interests in the six operating nuclear units at these facilities account for approximately 20% of our total summer planning reserve capacity and produced 42% of our energy generated during 2024.

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 decommissioning these facilities at the end of their licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning;
- 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, cybersecurity attacks or otherwise, including the payment of retrospective insurance premiums, whether at our own plants or the plants of other nuclear owners;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; 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 maintain an internal fund and an external trust fund to pay for the estimated cost of decommissioning our existing nuclear facilities. We continue to collect and deposit additional funds into these funds. The internal and external funds are invested in a diversified mix of equity and debt securities, the performance of which is subject to market performance risks. If the value of the investments in the funds significantly decrease or the anticipated decommissioning costs significantly increase, it is possible that the decommissioning costs could exceed the funds available and we would have to collect additional revenue from our members to pay the unfunded costs.

We could be adversely affected if we or third parties operating certain of our co-owned facilities are unable to continue to operate our facilities in a successful manner.

We rely on the successful operation of our generation facilities to provide our members' energy needs. The operation of our generating facilities may be adversely impacted by various factors, including:

- the risk of equipment and information technology failure or operator error;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- interruptions or shortages in fuel, water or material supplies;
- supply chain disruptions and the impact of any recently enacted or new tariffs;
- physical or cyber attacks against us or key suppliers or service providers;
- transmission constraints or disruptions;
- the impact of intermittent generation resources on our members' demand patterns;
- compliance with electric reliability organizations' mandatory reliability and record keeping standards, including mandatory cybersecurity standards;
- the ability to maintain a qualified workforce;
- an environmental event, such as a spill or release;
- labor disputes; or
- severe weather or catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events, or similar occurrences.

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 co-owned facilities that are operated by Georgia Power and Southern Nuclear. We rely on these third parties for the continued operation of these facilities to avoid potential interruptions in service from these facilities. If these third parties 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 "OUR BUSINESS—BUSINESS OVERVIEW—Relationship with Georgia Power Company" and "OUR BUSINESS—PROPERTIES—Co-Owners of Plants" and "—The Plant Agreements" for discussions of our relationship with Georgia Power and our co-owned facilities.

If we are unable to obtain an adequate supply of fuel, our ability to operate our facilities could be limited.

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, workforce shortages, cybersecurity incidents or other factors affecting our fuel suppliers, could result in us having insufficient levels of fuel supplies. A number of commodities, including natural gas and coal, have been affected in recent years by broader supply chain challenges and commodity availability constraints. Natural gas supplies may be unavailable due to increased demand during periods of exceptionally cold weather and are also subject to disruption due to natural disasters and similar events or infrastructure failure. Further, a significant increase in liquefied natural gas (LNG) demand may constrain the supply of natural gas available to us. Over the past few years, we have also managed rail-related delays in connection with our coal supply. Additionally, there are only a few facilities that fabricate fuel for our nuclear units and if there was an interruption in production at one of those facilities, it could impact our ability to obtain fuel for our nuclear generating facilities on a timely basis. Any failure to maintain access to or 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.

Georgia is projected to experience significant load growth over the next several years which may present risks to the electric system in Georgia and our members.

Georgia is projected to experience significant load growth over the next several years resulting from native load growth and the development of several large commercial projects, including data centers to meet the increased demand for artificial intelligence (AI) resources. Loads of 900 kilowatts or more in Georgia are subject to competition at initial operation. Our members have been selected to meet some of the additional large loads in their service territories and may be selected for more.

Significant load growth may put pressure on the existing generation and transmission infrastructure in Georgia and will require significant investments to meet the anticipated load growth. To the extent that any of our members serve large data centers, they will be subject to increased counterparty risk to customers that may consume a disproportionate percentage of their sales, which have historically been primarily residential. Changes in technology could impact the development and continued resource needs of data centers and any significant decrease in those needs could affect the counterparty's willingness or ability to pay for large amounts of electricity.

Our members will use the best information available to them to appropriately plan for their anticipated power needs. We do not serve all of our members' power supply requirements and they may seek additional generation from us or other third parties. If our members' actual load growth and continued demand is significantly lower than projected, costs related to any new facilities could increase certain members' cost of electric service, provided by us or other third parties, more than anticipated and could 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 more than 35 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 facility availability and compliance with applicable efficiency, reliability and environmental standards may require significant capital expenditures or operating reductions at certain of our facilities, and we may decide 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.

We and the other co-owners may retire our remaining coal-fired generation units in advance of our currently assumed retirement dates which could result in rate recovery challenges.

We own or lease a 60% interest in Plant Scherer Units No. 1 and No. 2 which constitutes 11% of our total summer planning reserve capacity. The percentage of gross energy generated by coal-fired resources we sell to our members has decreased from 45% in 2008 to 10% in 2024. This decrease was largely driven by other generation resources being more economical, our acquisition of additional natural gas-fired resources, the completion of Plant Vogtle Units No. 3 and No. 4, and the retirement of Plant Wansley in August 2022. Although projected load growth in Georgia has lessened some of the near-term pressure on coal retirements, additional lower cost generation could further displace our remaining coal-fired generation which may make continued operation uneconomical.

In addition to these pressures, potential new environmental standards could require additional capital expenditures or operating costs that make continued operation of the remaining units uneconomical. Some banking and insurance companies have also voluntarily implemented policies to limit lending to, investing in and insuring utilities that significantly rely on coal-fired generation assets. We are not aware that any of those policies have

directly impacted us to date. Similar pressures on coal producers have also increased and could impact our price and supply of coal.

Early retirement of our coal units could require us to recover the undepreciated costs for the unit over a shorter period. The ownership agreements for Plant Scherer, of which we own or lease 60% in each of Units No. 1 and No. 2, require the consent of participants owning at least 75% of the undivided ownership interest in that unit with respect to any decision to retire the unit. In January 2025, Georgia Power, who owns an 8.4% ownership interest in each of Scherer Units No. 1 and No. 2, as well as 75% of Unit No. 3, filed an integrated resource plan with the Georgia Public Service Commission that noted Georgia Power, as a result of significant projected load growth in Georgia, was extending commercial operation of Scherer Unit No. 3 beyond a previously expected retirement date of 2028. We have not made a decision regarding the retirement of Plant Scherer Units No. 1 or No. 2 prior to the end of our estimated useful life for the units. We will continue to evaluate the reliability, economics and related environmental requirements of Scherer Units No. 1 and No. 2 in order to provide our members with a balanced, reliable and cost-effective generation portfolio.

The ultimate impact of an early retirement on us and our members would depend on several factors, including the proposed retirement date, our ability to recover costs after the retirement date, the price and availability of any replacement energy and cannot be determined at this time. In order to mitigate the rate impact of any early retirement on our members, we would likely apply for regulatory accounting treatment to spread the early retirement costs over an extended period. These increased costs could affect our members' ability to perform their contractual obligations to us.

Financial Risk Factors

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, federal grants 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 and acquisitions 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 \$4.6 billion in loans from the Federal Financing Bank and a related loan guarantee from the Department of Energy. We have fully drawn those loans to fund \$4.6 billion of eligible project costs. We have also issued more than \$3.6 billion of first mortgage bonds to finance our portion of the Vogtle Units No. 3 and No. 4 construction costs and refinance Department of Energy-guaranteed loans that matured before the in-service date of Vogtle Unit No. 4, including an aggregate of \$700 million of green first mortgage bonds in June 2024 and January 2025. With these recent bond issuances, we have substantially completed our long-term funding for Vogtle Units No. 3 and No. 4.

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. We intend to apply for Rural Utilities Service funding for long-term financing for our new natural gas resource projects and for a significant amount of our ongoing capital expenditures related to existing plant operation and maintenance. 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. The timing and continued availability of Rural Utilities Service funding could also be impacted by federal administrative actions. 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 which would likely be at a higher cost.

We have also been awarded \$81 million by the Department of Energy under its GRIP Program to pay for a portion of the costs related to 75 megawatts of battery storage resources and received a conditional commitment from the Rural Utilities Service under its Empowering Rural America (New ERA) program to refinance outstanding

debt associated with Plant Wansley with a 0% loan. Recent statements and executive orders from the executive branch have created uncertainty as to the continued availability of funds under these programs. The final amount and availability of funding is subject to meeting program requirements and, with respect to the New ERA loan, entering into binding Agreements with the Rural Utilities Service.

Our access to both short-term and long-term funding remains an important factor in our existing financing plans and will be an important factor in connection with new capital investments. We have entered into multiple credit agreements that provide significant short-term and medium-term liquidity and have 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 would likely 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 uncertainty;
- 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;
- pandemic health events;
- geopolitical instability, war or threat of war; and
- actual or threatened cyber or physical attacks on our facilities or the facilities of unrelated energy companies.

Further, a number of lenders and investors are taking into account environmental, social and corporate governance criteria when making lending and investment decisions. Although we are not aware of any instances where our access to capital was limited due to these criteria, such considerations could potentially limit the number of lenders or investors who are willing to lend capital to us or other utility companies in the future.

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 capital expenditures or future acquisitions could be limited and our financial condition and future results of operations could be adversely affected.

Future capital expenditures are expected to be significant and will continue to increase our debt, which has constrained certain of our financial metrics and may also adversely affect our credit ratings, which would likely increase our borrowing costs and could decrease our access to capital.

We are in the process of developing and constructing over \$2 billion of natural gas resources for our members. These projects follow the recent completion of Vogtle Units No. 3 and No. 4, for which we added \$8.2 billion of

long-term debt, and the recent acquisition of four natural gas facilities. As we have financed generation assets in the past, we rely on external funding to finance additional generation resources. As of December 31, 2024, we had \$12.6 billion of long-term debt outstanding. As a result of these resource additions, our debt has 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 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 would likely increase our borrowing costs and could decrease our access to the credit and capital markets.

For most of the development and construction period for Vogtle units, our board of directors approved budgets to achieve margins for interest ratios of 1.14, which is greater than the minimum 1.10 margins for interest ratio required under our first mortgage indenture, in order to increase financial coverage during this period of generation expansion. In each of these years, we achieved the board-approved margins for interest ratio. Following completion of Vogtle Unit No. 4, our board of directors lowered the approved margins for interest ratio back to 1.10 for 2025.

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. Our primary fuel price exposure is to natural gas and, for 2024, natural gas expenses constituted 64% of our total fuel costs. 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. Historically, natural gas prices have been more volatile than other fuel sources. Geopolitical events or conflicts, the availability of shale gas, and increasing natural gas demand from LNG terminals along the Gulf Coast may have a significant impact on the cost and supply of natural gas. 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.

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 may 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, including how to respond to the significant amount of projected load growth in Georgia. Some of our members are also serving or will serve new large data centers in Georgia which can expose them to increased counterparty risk for a significant percentage of their sales. 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.

Regulatory, Legislative and Legal Risk Factors

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years. Potential new or stricter environmental laws and regulations, including those designed to address air and water quality, coal combustion residuals 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 or operating restrictions.

The Environmental Protection Agency, or EPA, finalized several rules over the course of 2024, including for greenhouse gas emissions. However, the Trump administration has issued executive orders and stated its intention to rescind, revise or replace some existing environmental regulations and the ultimate impact of recently finalized rules, several of which are in litigation, and any replacement rules is uncertain. On March 12, 2025, EPA announced 31 deregulatory actions it would be taking related to the “Unleashing American Energy” executive order. These actions continue a trend of U.S. presidential administrations relying on regulations and executive orders to implement environmental policies in the absence of Congressional action. This course of action creates instability and uncertainty of environmental regulations, and we may need to make decisions based on regulations or executive orders that are subsequently rescinded, revised or replaced. More stringent or new standards could require us to modify the design or operation of existing facilities and result in significant increases in the cost of electricity or decreases in the amount of energy (due to operational constraints) we provide to our members.

In April 2015, the EPA issued a rule to regulate coal combustion residuals from electric utilities as solid wastes. We and Georgia Power have proposed closure plans for our co-owned coal ash ponds to the Georgia Environmental Protection Division (EPD). Georgia Power’s proposed closure plans have been approved by the Georgia Public Service Commission but remain subject to EPD approval, and we cannot predict when they will be approved or whether either closure plan will require modifications. Costs associated with the closure of the ash ponds are reflected in the asset retirement obligations discussed below. If Georgia’s requirements for coal ash disposal are subsequently revised or the proposed closure plans are not approved, our estimated compliance costs could increase materially. In September 2015, the EPA also finalized a rule to revise effluent limitations guidelines (ELG) that apply to certain wastewater discharges from nuclear and fossil fuel-fired steam electric power plants. The 2015 ELG rule was later revised in October 2020. Then, in May 2024, EPA published a final supplemental ELG rule that generally increases the stringency of the current standards. However, because of the ELG compliance approach at Plant Scherer, we are not significantly impacted by the more stringent requirements of the supplemental rule. We are investing in facility upgrades to meet the coal combustion residuals rule and effluent limitations guidelines, and estimate our total capital cost for compliance at Plant Scherer to be approximately \$230 million of which \$170 million had been spent as of December 31, 2024. Expenditures for the settlement of related asset retirement obligations at our operating and retired coal plants are approximately \$600 million to \$800 million (in year of expenditure dollars), approximately \$70 million of which had been spent as of December 31, 2024. We continue to review the ultimate cost of these rules on our co-owned coal facilities which may be affected by any revised rules or litigation challenging those rules and cannot be determined at this time.

Litigation relating to environmental issues, including claims of property damage, personal injury or common law nuisance caused by plant emissions, including greenhouse gases, 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 also 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 “OUR BUSINESS —REGULATION—Environmental”.

Legislative and regulatory actions intended to address climate change and to reduce greenhouse gas emissions, including carbon dioxide, may result in significant compliance costs or expenses.

Concerns regarding climate change remain prevalent and the responses to those concerns by policymakers, regulators, investors, consumers and other stakeholders may affect us and our members in various ways. The costs associated with legislative or regulatory actions intended to reduce greenhouse gas emissions could be significant. Recent actions by the executive branch have created significant uncertainty regarding EPA’s recent carbon dioxide regulations.

In January 2025, President Trump signed an executive order to withdraw the United States from the Paris Climate Agreement and any attendant obligations. Under the Paris Climate Agreement’s format, the United States had previously announced a nationally determined contribution for reducing economy-wide carbon dioxide emissions by 50-52% below 2005 levels by 2030. In order to meet the United States nationally determined contribution, analyses indicate that the power sector would have to reduce carbon dioxide emissions by about 80% below 2005 levels by 2030.

In May 2024, EPA published final rules to replace the Affordable Clean Energy rule that limit greenhouse gas emissions from fossil-fueled electric generating units under Section 111 of the Clean Air Act in a manner consistent with the United States’ nationally determined contribution. If the final rule is implemented, it could have a significant negative impact on our existing operations and any future natural gas-fired resources. The final rule is likely to have a significant impact on the power sector and we are continuing to review the final rule to determine its impact on our operations. We believe that key assumptions in the rule, particularly regarding resource adequacy, availability and timing of required infrastructure and permitting, carbon capture and sequestration and the pace of technological advancements, continue to be unrealistic. The final rule has been challenged, and its ultimate impact will not be known until those legal challenges are complete. The Trump administration has also issued executive orders that are likely to impact the implementation of the final rule. At this time, we cannot predict the outcome or potential cost of this rule, but such costs could be significant.

Federal and state legislative and regulatory efforts to reduce the potential impacts of climate change and limit greenhouse gas emissions, including carbon dioxide, may continue over the long-term. The timing, cost and effect of any future laws or regulations attempting to address climate change and reduce greenhouse gas emissions are uncertain. However, such laws or regulations could impose operational restrictions on affected generating facilities and impose substantial costs on our business.

General Business Risk Factors

Technology and information systems utilized by us, our members and third parties with whom we do business are subject to risk of failure, loss of access or cybersecurity breaches which could affect our ability to operate and expose us to litigation, regulatory action and reputational harm.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure, which are part of broader interconnected systems. Because our generation resources are part of the nation’s energy infrastructure, we are at an increased risk of cyberattack.

Cyber actors, including those associated with foreign governments, have attacked and threatened to attack energy infrastructure. Various regulators have increasingly stressed that these attacks, including ransomware attacks, and attacks targeting utility systems and other critical infrastructure, are increasing in sophistication, magnitude, and frequency. In particular, certain actors, such as nation-state and state-sponsored actors, can deploy significant

resources and employ sophisticated methods to plan and carry out attacks. Risk of these attacks may escalate during periods of heightened geopolitical tensions.

Our generation assets and information technology systems, and 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. We and our third-party vendors have been subject to attempts to gain unauthorized access to our respective technology systems and confidential data and attempts to disrupt our operations. To date, none of the attempts on our systems have been successful; however, we cannot guarantee that our security efforts will prevent, detect or limit future attempts to breach or compromise our technology and information systems.

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 incident, we have comprehensive cybersecurity 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.

Advances in power generation and energy storage technologies, including decreasing renewable energy costs and 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. Renewable energy, distributed generation or energy storage technologies currently exist or are in development, such as large-scale batteries, fuel cells, micro turbines, windmills and solar cells, some of which are 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.

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, equipment manufacturing, natural gas pipelines, co-owner agreements, contracts related to the market price and supply of natural gas and coal, and power sales and purchases. Many of these transactions expose us to the risk that our counterparty may fail to perform its contractual obligations. If a defaulting counterparty is in poor financial condition, we may not be able to recover damages for any breach of contract.

In the context of facility construction and equipment manufacturing, a counterparty's failure to perform its contractual obligations under the applicable agreement could impact the project cost and schedule and potentially project completion.

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. 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 financial and operating results.

Risks Related to the Exchange Offers and the Exchange Bonds

Any Original Bonds that are not exchanged will continue to be restricted securities and, following completion of the exchange offers, will have a less liquid trading market.

Original Bonds that you do not tender or we do not accept will, following the exchange offers, continue to be subject to the restrictions on transfer applicable to the Original Bonds. The restrictions on transfer of your Original Bonds arise because we issued the Original Bonds under exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws. In general, you may only offer or sell the Original Bonds if they are registered under the Securities Act and applicable state securities laws, or offered and sold under an exemption from these requirements. We do not plan to register the Original Bonds under the Securities Act. For further information regarding the consequences of tendering your Original Bonds in the exchange offers, see the discussion below under the caption “THE EXCHANGE OFFERS—Consequences of Failure to Exchange.”

Because we anticipate that most holders of Original Bonds will elect to exchange their Original Bonds, we expect that the liquidity of the market for any series of Original Bonds remaining after the completion of the corresponding exchange offer will be substantially limited. Any Original Bonds tendered and exchanged in the exchange offers will reduce the aggregate principal amount of the Original Bonds outstanding. Following the exchange offers, if you do not tender your Original Bonds, you generally will not have any further registration rights, and your Original Bonds will continue to be subject to certain transfer restrictions. Accordingly, the liquidity of the market for the Original Bonds could be adversely affected by the exchange offers.

If an active trading market does not develop for the Exchange Bonds, you may be unable to sell the Exchange Bonds or to sell them at a price you deem sufficient.

The Exchange Bonds will be new securities for which there is no established trading market. We do not intend to apply for listing of the Exchange Bonds on any national securities exchange or to arrange for the Exchange Bonds to be quoted on any automated quotation system. As a result, we cannot provide any assurance as to:

- the liquidity of any trading market that may develop for the Exchange Bonds;
- the ability of holders to sell their Exchange Bonds; or
- the price at which holders would be able to sell their Exchange Bonds.

Even if a trading market develops, the Exchange Bonds may trade at higher or lower prices than their principal amount or purchase price, depending on many factors, including:

- prevailing interest rates;
- the number of holders of the Exchange Bonds;
- the interest of securities dealers in making a market for the Exchange Bonds; and
- our operating results.

If a market for the Exchange Bonds does not develop, purchasers may be unable to resell the Exchange Bonds for an extended period of time. Consequently, a holder of Exchange Bonds may not be able to liquidate its investment readily, and the Exchange Bonds may not be readily accepted as collateral for loans. In addition, market-making activities will be subject to restrictions of the Securities Act and the Securities Exchange Act of 1934.

In addition, if a large number of the holders of a series of Original Bonds do not tender Original Bonds or tender Original Bonds improperly, the limited amount of Exchange Bonds that would be issued or outstanding after we complete the corresponding exchange offer would adversely affect the development of a market for the Exchange Bonds.

You must comply with the procedures for the exchange offers in order to receive new, freely tradable Exchange Bonds.

Delivery of the Exchange Bonds in exchange for the Original Bonds tendered and accepted for exchange pursuant to the exchange offers will be made only after timely receipt by the exchange agent of the following:

- book-entry confirmation of a book-entry transfer of Original Bonds into the exchange agent's account at DTC, New York, New York as depository, including an agent's message (as defined herein) if the tendering holder does not deliver a letter of transmittal or certificates for Original Bonds;
- a completed and signed letter of transmittal (or facsimile thereof), with any required signature guarantees, or an agent's message in lieu of the letter of transmittal; and
- any other documents required by the letter of transmittal.

Therefore, holders of Original Bonds who would like to tender Original Bonds in exchange for Exchange Bonds should allow enough time for the Original Bonds to be delivered on time. We are not required to notify you of defects or irregularities in tenders of the Original Bonds for exchange. The Original Bonds that are not tendered or that are tendered but we do not accept for exchange will, following consummation of the corresponding exchange offer, continue to be subject to the existing transfer restrictions under the Securities Act and certain registration and other rights under the corresponding registration rights agreement will terminate. See "THE EXCHANGE OFFERS—Procedures for Tendering Original Bonds" and "THE EXCHANGE OFFERS—Consequences of Failure to Exchange."

Certain persons who participate in the exchange offers must deliver a prospectus in connection with resales of the Exchange Bonds.

Based on interpretations of the staff of the SEC contained in no-action letters to third parties, we believe that you may offer for resale, resell or otherwise transfer the Exchange Bonds without compliance with the registration and prospectus delivery requirements of the Securities Act. However, in some instances described in this prospectus under "PLAN OF DISTRIBUTION," certain holders of Exchange Bonds will remain obligated to comply with the registration and prospectus delivery requirements of the Securities Act to transfer the Exchange Bonds. If a holder subject to the registration and prospectus delivery requirements of the Securities Act transfers any Exchange Bonds without delivering a prospectus meeting the requirements of the Securities Act or without an applicable exemption from registration under the Securities Act, that holder may incur liability under the Securities Act. We do not and will not assume or indemnify such a holder against this liability.

The market price of the Exchange Bonds will fluctuate.

Any material differences between our actual results and the historical results contained in our annual, quarterly and current reports filed with the SEC could have a significant adverse impact on the market price of the Exchange Bonds, assuming a market for the Exchange Bonds develops. In the event that a market develops, prevailing interest rates may cause the Exchange Bonds to trade at higher or lower prices than their principal amount or purchase price. In addition, any downgrade of our credit ratings could have a significant adverse impact on the market price of the Exchange Bonds, assuming a market develops.

There can be no assurance that the use of proceeds from the sale of the Original Bonds to finance or refinance a portion of our interest in the Eligible Project will be suitable for the investment criteria of an investor.

We have allocated an amount equal to the net proceeds from the sale of each series of Original Bonds to finance or refinance a portion of our 30% interest in two nuclear units at Plant Vogtle, Units No. 3 and No. 4 (the “Eligible Project”). For additional information regarding Vogtle Units No. 3 and No. 4, see “OUR BUSINESS—OUR POWER SUPPLY RESOURCES—Recent and Future Power Resources—*Plant Vogtle Units No. 3 and No. 4.*”

Prospective investors should carefully review the information set out in this prospectus regarding the use of the net proceeds of the Original Bonds and must determine for themselves the relevance of such together with any other investigation such investor deems necessary. In particular, no assurance is given by us that the use of the net proceeds of the Original Bonds to finance or refinance a portion of our interest in the Eligible Project will satisfy (or will continue to satisfy), in whole or in part, any present or future investor expectations or requirements, taxonomies or standards or other investment criteria or guidelines with which such investor or its investments are required to comply, whether by any present or future applicable laws or regulations or by such investor’s own bylaws or other governing rules or investment portfolio mandates, ratings mandates or criteria, taxonomies or standards, or other independent expectations, in particular with regard to any direct or indirect environmental, sustainability or social impact related to the Eligible Project. Any failure of the allocation of the net proceeds from the sale of the Original Bonds to the Eligible Project to satisfy investor expectations or requirements or achieve expected outcomes could have an adverse effect on the market price of the Exchange Bonds.

There is no legal, regulatory or market definition of or standardized criteria for what constitutes a “green” project, and any such designation made by third parties with respect to the Exchange Bonds may not be suitable for the investment criteria of an investor.

There is currently no single, agreed-upon definition (legal, regulatory or otherwise) of, nor market consensus as to what constitutes, a “green” project, or as to what precise attributes are required for a particular project to be defined as “green”. No assurance can be given that a clear definition or consensus will develop over time or, if such definition or consensus develops in the future, that the Eligible Project will meet such criteria. Accordingly, no assurance is or can be given to investors that the Eligible Project will meet any or all investor expectations regarding “green” performance objectives, or that any adverse environmental, social or other impacts, environmental, social and governance (“ESG”) controversies or material changes will not occur during the operation of the Eligible Project.

No assurance or representation is given as to the suitability or reliability for any purpose whatsoever of any opinion or certification of any third party (whether or not solicited by us), including the Second Party Opinions, that was made available in connection with the issuance of the Original Bonds.

No assurance or representation is given as to the suitability or reliability for any purpose whatsoever of any opinion or certification of any third party (whether or not solicited by us) made available in connection with the issuance of the Original Bonds and, in particular, with respect to whether the Eligible Project fulfills any environmental or other criteria. Any such opinion or certification is not, and should not be deemed to be, a recommendation by us, or any other person to participate in the exchange offers or buy, sell or hold the Exchange Bonds. Any such opinion or certification is only current as of the date that opinion or certification was initially issued. Prospective investors must determine for themselves the relevance of any such opinion or certification or the information contained therein or the provider of such opinion or certification. Any withdrawal of any such opinion or certification or any additional opinion or certification attesting that we are not complying in whole or in part with any matters for which such opinion or certification is opining or certifying may have an adverse effect on the market price of the Exchange Bonds or result in adverse consequences for certain investors with mandates to invest in securities to be used for a particular purpose.

We do not intend to list the Exchange Bonds on, and the Exchange Bonds may never be listed or admitted to, any dedicated “green” or other equivalently labeled segment of any stock exchange or securities market, and the Exchange Bonds may not be included in any green bond or similar index, and any such potential listing, admission or inclusion may not be indicative that the Exchange Bonds will be suitable for the investment criteria of an investor.

We do not intend to apply for the Exchange Bonds to be listed or admitted to trading on any dedicated “green” or other equivalently labeled segment of any stock exchange or securities market (whether or not regulated), and there is no assurance that the Exchange Bonds will be included in any green bond or similar index. Moreover, even if the Exchange Bonds were to be listed or admitted to trading on any such segment of any stock exchange or securities market or included in any green bond or similar index, no representation or assurance can be given by us, any initial purchaser or any other person:

- that such listing, admission or inclusion would satisfy, in whole or in part, any present or future investor expectations or requirements, taxonomies or standards or other investment criteria or guidelines with which such investor or its investments are required to comply, whether by any present or future applicable laws or regulations or by such investor’s own bylaws or other governing rules or investment portfolio mandates, ratings mandates or criteria, taxonomies or standards, or other independent expectations, in particular with regard to any direct or indirect environmental, social or sustainability impact of any projects or uses, the subject of or related to, the Eligible Project; or
- that any such listing or admission to trading or inclusion in any index will be maintained during the life of the Exchange Bonds.

In the event that the Exchange Bonds are listed on any such exchange or securities market or included in any such index, any change to the listing or admission status of the Exchange Bonds or their inclusion in any such index, including but not limited to any change that causes the Exchange Bonds to no longer be listed or admitted to trading on any stock exchange or securities market or included in any index, may have a material adverse effect on the market price of the Exchange Bonds or result in adverse consequences for certain investors with portfolio mandates to invest in securities to be used for a particular purpose.

The market price of the Exchange Bonds may be negatively affected to the extent that perception by investors of the suitability of the Exchange Bonds as “green” bonds deteriorates or demand for green investment products diminishes.

Perception by investors of the suitability of the Exchange Bonds as “green” bonds could be negatively affected by dissatisfaction with the Eligible Project, controversies involving the environmental, social or sustainability impact of our business or industry, as well as our determination of whether controversies are material, evolving standards or market consensus as to what constitutes a “green” bond or the desirability of investing in “green” bonds or any opinion or certification as to the suitability of the Exchange Bonds as “green” bonds no longer being in effect.

The Eligible Project may have complex direct or indirect environmental, sustainability or social impacts, and adverse environmental or social impacts may occur during the operation of the Eligible Project. In addition, projects may become controversial or criticized by activist groups or other stakeholders, which could have a negative effect on market price of the Exchange Bonds.

The market price of the Exchange Bonds may be negatively affected to the extent investors are required or choose to sell their holdings due to deterioration in the perception by the investor or the market in general as to the suitability of the Exchange Bonds as “green” bonds. The market price of the Exchange Bonds may be also negatively affected to the extent demand for sustainability-themed investment products diminishes due to evolving investor preferences, increased regulatory or market scrutiny on funds and strategies dedicated to sustainability or environmental, social or governance themed investing or for other reasons. The market for investments denoted as “green” is new and may be volatile.

You will have no remedies under the Exchange Bonds or the first mortgage indenture if we fail to allocate an amount equal to the net proceeds from the sale of the Original Bonds to the Eligible Project or to satisfy related reporting obligations and other undertakings.

Neither the Exchange Bonds nor the first mortgage indenture requires or will require us to use the net proceeds from the sale of the Original Bonds as described under “USE OF PROCEEDS” or to satisfy the reporting and other undertakings described under “USE OF PROCEEDS—Reporting.” Any failure by us to comply with the foregoing will not constitute a breach of or default under the Exchange Bonds or the first mortgage indenture. As a result, it will not be an event of default under the first mortgage indenture if we fail to allocate an amount equivalent to the net proceeds from the sale of the Exchange Bonds to the Eligible Project or to satisfy the reporting and other undertakings as described under “USE OF PROCEEDS” and holders of the Exchange Bonds will have no remedies under the Exchange Bonds or the first mortgage indenture for any such failure.

USE OF PROCEEDS

We will not receive any cash proceeds from the issuance of the Exchange Bonds pursuant to the exchange offers. In consideration for issuing the Exchange Bonds as contemplated in this prospectus, we will receive in exchange a like principal amount of Original Bonds. The Original Bonds surrendered in exchange for the Exchange Bonds will be retired and cancelled and cannot be reissued. Accordingly, the issuance of the Exchange Bonds will not result in any change in our capitalization.

We used the net proceeds from the sale of the Original Bonds for (i) the long-term financing and refinancing of development, construction, testing and other pre-operational expenditures related to our interest in Vogtle Units No. 3 and No. 4, two new advanced-design nuclear units that will provide our members with approximately 727 megawatts of emission-free baseload generating capacity (“Vogtle Units No. 3 and No. 4”) and (ii) to refinance outstanding commercial paper issued to finance expenditures related to our interest in Vogtle Units No. 3 and No. 4, including Department of Energy guaranteed loan repayments made prior to the commercial operation of Vogtle Unit No. 4. We have determined that Vogtle Units No. 3 and No. 4 is an Eligible Project pursuant to our green bond framework (the “Eligible Project”).

Green Bond Framework

We have developed a Green Bond Framework (the “Framework”) under which we are able to issue green bonds. The Framework has been developed in alignment with The ICMA Green Bond Principles, 2021 (“GBP”), which are voluntary process guidelines for best practices when issuing green bonds.

Eligible Green Categories

Nuclear Energy

- Long-term financing and refinancing of development, construction, testing and other pre-operational expenditures, including interest during construction, related to our interest in Vogtle Units No. 3 and No. 4.
- Refinancing outstanding commercial paper issued to finance expenditures related to our interest in Vogtle Units No. 3 and No. 4, including Department of Energy guaranteed loan repayments made prior to commercial operation of Vogtle Unit No. 4.

All investments in the nuclear power category will be in relation to facilities licensed by the U.S. Nuclear Regulatory Commission, including complying with regulations in relation to safety and waste management and that meet our commitments to risk management and nuclear plant safety.

For the avoidance of doubt, we will not allocate proceeds from the Original Bonds to finance power generation projects for which fossil fuels are the primary source of fuel.

Process for Project Evaluation and Selection

In accordance with the Eligible Project criteria set forth in the Framework, we have determined that Vogtle Units No. 3 and No. 4 align with our sustainability objectives, internal policies, and guidelines and is an Eligible Project.

Vogtle Units No. 3 and No. 4 entered commercial operation on July 31, 2023 and April 29, 2024, respectively. From these units, we will provide electric cooperative consumers across Georgia with reliable, emission-free nuclear energy for decades to come. We own a 30% undivided interest in Vogtle Units No. 3 and No. 4.

Management of Proceeds

We allocated the net proceeds from the Original Bond issuances to finance or refinance the Eligible Project. The allocated and unallocated Original Bond proceeds will be tracked using an internal tracking system by our Treasury team.

Net proceeds can be attributed to Eligible Project expenditures that are financed or refinanced before the issuance of the Original Bonds. We will strive to fully allocate the net proceeds from the sale of the Original Bonds as soon as practicable within 12 months of the issuance.

Pending full allocation of an amount equal to the net proceeds of the Original Bonds, proceeds may be (i) temporarily invested in cash or cash equivalents that do not include greenhouse gas-intensive investment or (ii) used to repay existing borrowings in accordance with our normal liquidity management policies.

Payment of principal, premium (if any) and interest on the Exchange Bonds will be made from our general account and will not be linked to the performance of the Eligible Project. The Exchange Bonds will be secured under the first mortgage indenture, which includes our 30% interest in Vogtle Units No. 3 and No. 4 and substantially all of our other owned tangible and certain of our intangible property. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE.” Neither the Exchange Bonds nor the First Mortgage Indenture requires or will require us to allocate the net proceeds from the sale of the Original Bonds to the Eligible Project or to satisfy the reporting and other undertakings described under this “USE OF PROCEEDS” section. Any failure by us to comply with the foregoing will not constitute a breach of or default under the Exchange Bonds or the first mortgage indenture governing the Exchange Bonds. See “RISK FACTORS — *You will have no remedies under the Exchange Bonds or the First Mortgage Indenture if we fail to allocate an amount equal to the net proceeds from the sale of the Exchange Bonds to the Eligible Project or to satisfy related reporting obligations and other undertakings.*”

Reporting

Allocation Reporting

On an annual basis until full allocation of the net proceeds of the Original Bonds, we will update investors on the allocation of net proceeds for the Original Bonds (“Green Bond Report”). The Green Bond Report will include the following information, and will be available on our website: (i) a summary of outstanding Original Bonds and Exchange Bonds, (ii) the amount of net proceeds from any Original Bonds that have been allocated to the Eligible Project; (iii) the remaining balance of net proceeds from the Original Bonds yet to be allocated to the Eligible Project at the end of the reporting period; and (iv) the proportion of the proceeds used for financing of new projects and refinancing of existing projects.

Impact Reporting

On an annual basis, until full allocation of net proceeds from the Original Bonds, we will also report on relevant environmental impact metrics from the Original Bonds and the Exchange Bonds. The Green Bond Report may include, for example, one or more of the following indicators or other indicators that show the direct and/or indirect benefits generated: (i) greenhouse gas emissions reduced or avoided; and (ii) annual nuclear energy generation (MWh).

External Review

Second Party Opinion

In connection with the initial issuance of each series of Original Bonds, we retained an independent second party opinion provider to provide a Second Party Opinion on the environmental benefits of the Framework as well as the alignment to the GBP.

Assurance

We have engaged a third party to complete a verification of our allocation of net proceeds to Eligible Projects.

For the avoidance of doubt, none of the Framework, the Second Party Opinions or the Green Bond Report are, and none shall be deemed to be, incorporated by reference into or form a part of this prospectus.

Independent Second Party Opinion on Green Bonds Designations and Disclaimer

The Second Party Opinions issued in connection with the initial issuance of each series of Original Bonds do not and are not intended to make any representation or give any assurance with respect to any other matter relating to the Original Bonds or the Exchange Bonds. The Second Party Opinions are not a recommendation to any person to purchase, hold, or sell the Exchange Bonds and designations do not address the market price or suitability of the Exchange Bonds for a particular investor and do not and are not in any way intended to address the likelihood of timely payment of interest or principal when due.

SELECTED FINANCIAL DATA

The following table presents selected historical financial and statistical data. The financial data presented as of the end of and for each year in the three-year period ended December 31, 2024, has been derived from our consolidated audited financial statements. This data should be read in conjunction with “MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS” and “APPENDIX A - AUDITED FINANCIAL STATEMENTS.”

	(dollars in thousands)		
	2024	2023	2022
STATEMENTS OF REVENUES AND EXPENSES DATA			
Operating revenues:			
Sales to members	\$ 2,145,522	\$ 1,681,566	\$ 1,974,683
Sales to non-members	36,325	58,619	155,454
Operating expenses	\$ 1,698,351	\$ 1,463,119	\$ 1,936,086
Other income, net	\$ 67,390	\$ 81,049	\$ 72,244
Net interest charges	\$ 480,385	\$ 292,325	\$ 204,591
Net margin	\$ 70,501	\$ 65,790	\$ 61,704
BALANCE SHEET DATA			
Assets:			
Construction work in progress	\$ 320,167	\$ 3,294,641	\$ 7,716,035
Total electric plant	\$ 12,712,076	\$ 12,680,395	\$ 12,490,108
Total assets	\$ 16,477,538	\$ 16,524,851	\$ 16,489,370
Capitalization:			
Patronage capital and membership fees	\$ 1,328,418	\$ 1,257,917	\$ 1,192,127
Long-term debt and obligations under finance leases	12,686,674	12,149,489	12,001,694
Obligation under Rocky Mountain transactions	31,910	29,862	27,945
Other	5,715	5,152	2,256
Total long-term debt and equities	\$ 14,052,717	\$ 13,442,420	\$ 13,224,022
Less: Long-term debt and finance leases due within one year	398,979	384,426	322,102
Less: Unamortized debt issuance costs and bond discounts	120,328	120,560	114,142
Total capitalization	\$ 13,533,410	\$ 12,937,434	\$ 12,787,778
OTHER DATA			
Megawatt hours sold to members ^(1,2)	31,001,082	28,289,147	25,634,984
Member energy requirements (MWh) ⁽³⁾	44,245,782	41,370,456	42,175,373
Percentage of Member energy requirements supplied	70 %	68 %	58 %
Member revenues per kWh sold	6.92 ¢	5.94 ¢	7.70 ¢
Equity Ratio ⁽⁴⁾	9.5 %	9.4 %	9.0 %
Margins for Interest Ratio ⁽⁵⁾	1.14	1.14	1.14

(1) Includes energy supplied to members for resale at wholesale. Also includes energy we supplied to our own facilities.

(2) For 2024 and 2023, excludes test energy kilowatt-hours from Plant Vogtle Units No. 3 and No. 4 supplied to members. Revenues and costs associated with test energy were capitalized.

(3) 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 “OUR BUSINESS – OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources.” Also includes energy we supplied to our own facilities.

- (4) Our equity ratio is calculated, pursuant to our first mortgage indenture, by dividing patronage capital and membership fees by total capitalization plus unamortized debt issuance costs and bond discounts and long-term debt and finance leases due within one year (“Total long-term debt and equities” in the table above). We have no financial covenant that requires us to maintain a minimum equity ratio; however, a covenant in the first mortgage indenture restricts distributions of equity (patronage capital) to our members if our equity ratio is below 20%. We also have covenants in three of our line of credit agreements that require us to maintain minimum total patronage capital, the highest of which is \$900 million.
- (5) Our margins for interest ratio is calculated on an annual basis by dividing our margins for interest by interest charges, both as defined in our first mortgage indenture. The first mortgage indenture obligates us to establish and collect rates that, subject to any necessary regulatory approvals, are reasonably expected to yield a margins for interest ratio equal to at least 1.10 for each fiscal year. In addition, the first mortgage indenture requires us to demonstrate that we have met this requirement for certain historical periods as a condition to issuing additional obligations under the first mortgage indenture. For 2022, 2023 and 2024, our board of directors approved a budget to achieve a 1.14 margins for interest ratio, above the minimum 1.10 ratio required by the first mortgage indenture. For 2025, our board of directors approved a budget to achieve a 1.10 margins for interest ratio. As our capital requirements continue to evolve, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

OUR BUSINESS

BUSINESS OVERVIEW

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.

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 2.2 million electric consumers (meters) representing approximately 4.7 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 prospectus.

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.

Power Supply Business

We provide wholesale electric service to our members for a significant portion of their aggregate power requirements primarily from our fleet of generation assets but also with power purchased from other power suppliers from time to time. In 2024, we supplied energy that accounted for approximately 70% of the retail energy requirements of our members. 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.”

As of December 31, 2024, our fleet of generating units totaled 9,323 megawatts of summer planning reserve capacity, which included 729 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. We also supply financial and management services to support Green Power EMC's purchase of energy from 820 megawatts of renewable resources, including, low-impact hydroelectric, landfill gas and solar facilities. See “– Relationship with Green Power EMC,” “OUR POWER SUPPLY RESOURCES,” “OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources” – and “PROPERTIES – Generating Facilities.”

In 2024, one of our members, Jackson EMC, accounted for approximately 18% of our total revenues. Each of our other members accounted for less than 10% of our total revenues in 2024.

Wholesale Power Contracts

We have a wholesale power contract with each member that is substantially similar. Each wholesale power contract extends through December 31, 2085 and will 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 resource is completed, delayed, terminated, operable, operating, retired, sold, leased, transferred 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 resources, although not all members participate in all resources. For any future generation or purchased power 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 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. In the event a member defaults on all or a portion of its payment obligation, the default amount is shared first among the participating members in each resource in which the defaulting member participates. If all these 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. 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 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 Trust Company, National Association, as trustee (successor to U.S. Bank National Association), 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, 2024, our equity ratio was 9.5%.

As of December 31, 2024, we had approximately \$12.4 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. The timing and continued availability of Rural Utilities Service funding could also be impacted by federal administrative actions. The proposed budget for fiscal year 2025, which began October 2024, includes an aggregate loan program level of \$6.5 billion. 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 formula rate contained in the wholesale power contracts, and
- changes to plant ownership and operating agreements.

As of December 31, 2024, we had \$2.8 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 over \$3.0 billion of our obligations under a multi-advance term loan facility with the Federal Financing Bank. On March 22, 2019, we and the Department of Energy executed an amended and restated loan guarantee agreement that added \$1.6 billion to the loan guarantee. In connection with the increase of the loan guarantee, we entered into additional loan documents with the Federal Financing Bank to increase the aggregate amount available under the term loan facility. Proceeds of advances made under these facilities have been used to reimburse us for over \$4.6 billion of 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 have advanced all amounts available under the Department of Energy-guaranteed loans. In 2020, we began making principal payments on these loans and, at December 31, 2024, we had \$4.1 billion outstanding. All advances received under this facility are secured under our first mortgage indenture.

Under the 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 assets pledged under our first mortgage indenture,
- 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.

For additional information regarding the terms of the loan guarantee agreement, see Note 7a of Notes to Consolidated Financial Statements in Appendix A. For additional information on Vogtle Units No. 3 and No. 4, see “OUR POWER SUPPLY RESOURCES – Recent and 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 accounts payable, payroll, auditing, human resources, campus services, telecommunications and information technology at cost.

We have made loans to Georgia System Operations primarily for the purpose of financing its capital expenditures. As of December 31, 2024, the balance of the loans outstanding was \$11.0 million. Georgia System Operations has an additional \$10.0 million loan from us, that became available to draw on January 1, 2025.

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. Georgia Power, on behalf of itself as a co-owner and as agent for the other co-owners, is responsible for the operation of Plants Hatch, Scherer and Vogtle. Georgia Power is also a co-owner of the Rocky Mountain Pumped Storage Hydroelectric Facility which we co-own and operate. For further information regarding the agreements between Georgia Power and us, see “PROPERTIES – Fuel Supply,” “– Co-Owners of Plants – *Georgia Power Company*” and “– The Plant Agreements.” 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 (see “– Competition”). For further information regarding our members' relationships with Georgia Power, see “OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Service Area and Competition.”

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 summer planning reserve capacity of 729 megawatts. We provide operations, financial and management services to Smarr EMC. See “OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources.”

Relationship with Green Power EMC

Green Power Electric Membership Corporation, owned by our 38 members, is a Georgia electric membership corporation specializing in the purchase of renewable energy for its members. As of December 31, 2024, Green Power EMC purchased energy from 820 megawatts of renewable energy resources. By the end of 2027, the capacity is expected to increase by at least 447 megawatts, bringing the total capacity to more than 1,267 megawatts. We supply financial and management services to Green Power EMC. For more information on the renewable resources of Green Power EMC, see “OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Green Power EMC*.”

Competition

Under current Georgia law, our members generally have the exclusive right to provide retail electric service in their respective territories. However, the Georgia Territorial Act permits 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. Georgia is projected to experience significant load growth over the next several years. Our members are actively engaged in competition with other retail electric suppliers for a significant amount of new commercial and industrial loads. The number of

commercial and industrial loads served by our members continues to increase annually, and our members may evaluate additional generation resources from us or other third parties to meet this additional demand. This limited 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 routinely consider, along with our members, a wide array of potential actions to meet future power supply needs, maintain competitive rates, adapt to technological innovations, including distributed generation and energy storage technologies, and respond to the evolving competitive and regulatory landscape. 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.

Regulation of greenhouse gas emissions has the potential to affect energy suppliers, including us and our competitors, differently, depending on the relative greenhouse gas emissions from a supplier's sources and the nature of the regulation. Some of our generation sources emit greenhouse gases while others emit none. Comparatively, our competitors may rely on sources that emit proportionately more or less greenhouse gases than we do. Further, many of our members' third-party suppliers also rely 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 any greenhouse gas regulation of these suppliers affects our members. We believe our and our members' diverse portfolios of generation facilities, including the diversity of third-party suppliers, would mitigate impacts on our and our members' competitiveness resulting from any regulation. 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 (including broadband) 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. Among other conditions, for members providing broadband services through an affiliate, the Georgia Public Service Commission must approve cost allocations designed to ensure that cross-subsidizations do not occur between the broadband services and the electric and/or gas services of a member or its affiliates.

Further, a member's power supply planning may include considering an 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 are based upon budgeted expenditures and are generally recognized and billed to our members in substantially equal monthly installments over the course of the year. We may recognize capacity revenues that exceed our actual fixed costs and targeted margins in any given interim reporting period. At each interim reporting period, we assess our projected revenue requirements through year end and if required, we reduce our capacity revenues and recognize a refund liability to our members. See Note 1e of Notes to Consolidated Financial Statements in Appendix A for information regarding revenue recognition.

Human Capital

Our success depends on the people who are part of our company. We believe that in order to deliver superior performance and maximize the value of our members' investment, we must attract and retain the most qualified workforce available. We further believe that a strong corporation requires initiative, commitment and talent from its employees and that exceptional results evolve from diversity, continuous improvement, personal development and the contributions of many working toward common goals. We are focused on fostering innovation and leadership with our associates. We also place a strong emphasis on training because we know this ultimately leads to our associates' professional success and the success of our company.

As of December 31, 2024, we had 379 employees. Substantially all of our associates are full-time employees and are located in Georgia. We have a formal Code of Conduct that, among other things, requires that we treat each other, and those outside our company with whom we do business, professionally and with fairness and respect. We must also conduct ourselves in a manner that promotes a favorable image of our company and a positive and professional workplace environment that promotes harmonious relationships among each other and our members.

We strive to provide fair and equitable compensation to each of our associates through a combination of competitive base pay, performance incentives, retirement plans and other benefits. 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. We set uniform performance goals at the corporate level. Those goals are the same for both executive officers and non-executive associates as achieving these performance incentives requires the effort and attention of associates across our business, see “EXECUTIVE COMPENSATION – Compensation Discussion and Analysis – *Corporate Goals for Performance Pay.*”

We are dedicated to creating and maintaining an environment that respects and values diverse perspectives and experiences, recognizes the rights of all individuals to mutual respect, and accepts others without biases based on differences of any kind.

Safety is a key concern of our management team. As an electric generation utility, we are committed to providing a safe work environment for all our associates. Our corporate goals, which are reflected in the performance pay component of total compensation, reflect a commitment to provide comprehensive safety training and education and continue to find new ways to reduce workplace hazards.

As an electric cooperative, we are also committed to being a positive influence in the communities we serve. To accomplish this goal, we support and encourage our associates to participate in a variety of initiatives and activities that help the communities where we and our members live and work.

OUR POWER SUPPLY RESOURCES

General

We supply capacity and energy to our members for a portion of their requirements from our fleet of generating assets. In 2024, we supplied approximately 70% of the retail energy requirements of our members. Our members purchased the remaining 30% from a variety of suppliers, including Green Power EMC (renewable resources), Smarr EMC (gas-fired resources), Southeastern Power Administration (hydroelectric power), and several power marketers and other wholesale suppliers. For more detailed information on these other purchases, see “OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources.”

Generating Plants

As of December 31, 2024, our fleet of generating units totaled 9,323 megawatts of summer planning reserve capacity, including 729 megawatts of Smarr EMC assets, which we manage. Our generation portfolio includes interests in nuclear, coal, natural gas, oil and hydro units. Georgia Power, the Municipal Electric Authority of Georgia (MEAG) and the City of Dalton also have interests in eight of these units at Plants Hatch, Vogtle and Scherer. Georgia Power serves as operating agent for these eight units. Georgia Power also has an interest in the three units at Rocky Mountain, which we operate. In addition to our 37 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

As of December 31, 2024, we had no material power purchase or sale agreements.

We supply financial and management services to support Green Power EMC's purchase of energy from 820 megawatts of renewable resources, plus an additional 447 megawatts under contract to be constructed by the end of 2027. See “OUR MEMBERS AND THEIR POWER SUPPLY RESOURCES – Member Power Supply Resources – *Green Power EMC*.”

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.

We are a member of the Southeast Energy Exchange Market (SEEM) which began operating in 2022. SEEM, whose members include the traditional electric operating companies and many of the other electric service providers in the Southeast, is an extension of the existing bilateral market in which participants use an automated, intra-hour energy exchange to buy and sell power near the time the energy is consumed, utilizing available unreserved transmission. Our participation in SEEM has had minimal impact on our business to date. In 2023, the U.S. Court of Appeals for the District of Columbia Circuit vacated certain Federal Electric Regulatory Commission (FERC) orders related to SEEM and remanded the proceeding to the Federal Electric Regulatory Commission. Upon remand, on March 14, 2025, FERC in a unanimous decision affirmed its acceptance of SEEM, rejecting arguments that the market's structure unfairly limits competition. Protestors may appeal and so the ultimate outcome of this matter cannot be determined at this time.

Recent and Future Power Resources

Plant Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), 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 nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company, Inc. as its agent for licensing, engineering, procurement and contract management.

Georgia Power placed Unit No. 3 in service on July 31, 2023 and placed Unit No. 4 in service on April 29, 2024.

Our ownership interest and proportionate share of the cost to construct Vogtle Units No. 3 and No. 4 is 30%, representing 727 megawatts of nameplate capacity, as constructed. As of December 31, 2024, our actual costs related to the new Vogtle units were approximately \$8.3 billion, net of \$1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and approximately \$433 million we received from Georgia Power pursuant to the cost-sharing provisions in a settlement agreement with Georgia Power. We estimate that our proportionate share of remaining additional capital costs to be incurred on the project through the end of 2025 to be \$10-\$15 million.

Smarr Combined Cycle Generation Facility

We and our members have approved the development and construction of a two-unit combined cycle generation facility to be located on land we own adjacent to the Smarr Energy Facility in Monroe County, Georgia. We have entered into a purchase agreement with the equipment manufacturer for the two units, which have a combined generation capacity of approximately 1,425 megawatts. Our preliminary cost estimate for this facility is approximately \$1.8 billion to \$2.3 billion and the projected commercial operation date is 2029. We are currently in the process of selecting an engineering, procurement and construction contractor for the project and will narrow our cost estimate range following that selection. In connection with these units, we have entered into agreements to provide firm capacity on new natural gas pipeline infrastructure to meet our anticipated fuel supply needs.

Talbot Combustion Turbine Unit No. 7

We and our members have also approved the development and construction of an approximately 240-megawatt combustion turbine unit to be constructed at our Talbot Energy Facility in Talbot County, Georgia. We have entered into a purchase agreement with the equipment manufacturer for the unit. Our preliminary cost estimate for this unit is approximately \$360 million and the projected commercial operation date is 2029. In connection with this additional resource, we entered into agreements to provide firm capacity on new natural gas pipeline infrastructure to meet our anticipated fuel supply needs.

Walton County Plant

In June 2024, we acquired Walton County Power, LLC, which owns the Walton County Power Plant, located near Monroe, Georgia, from Mackinaw Power, LLC, an affiliate of the Carlyle Group, Inc. Walton County is a three-unit 450-megawatt summer planning reserve capacity natural gas-fired combustion turbine facility. In October 2024, we assumed direct ownership of the facility and eliminated Walton County Power, LLC.

Some of our members elected to take service (scheduling members) at the date of acquisition and some members have elected to defer (deferring members) their share of output through a date no later than January 2028. Prior to the deferring members' use of Walton, their share of output is being sold into the wholesale market. Residual net results of operations, including related interest costs of deferring members are deferred as a regulatory asset. This regulatory asset will be amortized over the then remaining life of the plant, estimated to be 24 years at

January 2028. Amortization of a deferring member's share of the regulatory asset will begin upon taking service. Revenues and costs of output associated with scheduling members are being recognized in the current period.

Grid Resilience and Innovation Partnerships (GRIP) Program

In October 2024, the Georgia Environmental Finance Authority, together with Oglethorpe, Georgia Transmission Corporation and Georgia System Operations Corporation, were awarded a \$250 million grant under the Department of Energy’s Grid Resilience and Innovation Partnerships (GRIP) Program. Oglethorpe expects to utilize approximately \$81 million of the total award for an aggregate of 75 megawatts of utility-scale battery storage resources for our members. We estimate that the total cost of these battery storage resources will be approximately \$200 to \$250 million, before the application of any grant proceeds. Our projected commercial operation dates for these resources are in 2029 and 2030. Awards under the Department of Energy’s GRIP program are currently subject to administrative review and the ultimate availability of funds are not certain. Receipt of any grant proceeds is subject to meeting program requirements. If these grant funds become unavailable for this project, we and our members will reassess whether or not to continue with this project.

We and our members may also consider additional generation beyond these resources in the future. See “RISK FACTORS” for a discussion of certain risks associated with these new generation projects.

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

Our members serve approximately 2.2 million electric consumers (meters) representing approximately 4.7 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. Selected financial and statistical information for our 38 members for the most recent three year period for which information is available is attached as Appendix B to this prospectus.

The following table shows the aggregate peak demand and energy requirements of our members for the years 2022 through 2024, and also shows the amount of their energy requirements that we supplied. From 2022 through 2024, peak demand of the members and their energy requirements have fluctuated based on various factors. In July 2024, our member system hit a new summer peak demand of 10,092 megawatts, slightly exceeding our members'

prior summer peak of 10,088 megawatts in August 2023. In December 2022, our member system hit its overall peak demand of 10,810⁽⁴⁾ megawatts.

	Member Peak Demand (MW) ⁽¹⁾	Member Summer Peak Demand (MW)	Member Winter Peak Demand (MW)	Member Energy Requirements (MWh)	
				Total ⁽²⁾	Supplied by Oglethorpe ^(3,5)
2024	10,236	10,092	10,236	44,245,782	31,001,082
2023	10,088	10,088	8,183	41,370,456	28,289,147
2022	10,810 ⁽⁴⁾	10,018	10,810	42,175,373	25,634,984

- (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. Also includes energy we supplied to our own facilities.
- (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.” Also includes energy we supplied to our own facilities.
- (3) Includes energy supplied to members for resale at wholesale. Also includes energy we supplied to our own facilities.
- (4) System peak hour demand measured at our generating resources was 11,077 megawatts and system peak hour demand measured at our members' delivery points was 10,810 megawatts.
- (5) For 2024 and 2023, excludes test energy megawatt-hours from Plant Vogtle Units No. 3 and No. 4 supplied to members. Revenues and costs associated with test energy were capitalized.

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 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 premises and the electric utility is unwilling or unable to comply with an order from the Georgia Public Service Commission regarding the service.

The Georgia Territorial Act allows 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. Georgia is projected to experience significant load growth over the next several years. Our members, with our support, are actively engaged in competition with other retail electric suppliers for a significant amount of new commercial and industrial loads. The number of commercial and industrial loads served by our members continues to increase annually, and our members may evaluate additional resources from us or other third parties to meet this additional demand. This limited 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 “BUSINESS OVERVIEW – 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 “OUR BUSINESS – 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 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, Okefenoke Rural 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 budget for fiscal year 2025, which began October 2024, includes a loan program level of \$6.5 billion. 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 “OUR BUSINESS – 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, 2085. The members' transmission service agreements include certain elections for load growth above 2015 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 “OUR BUSINESS – Relationship with Georgia System Operations Corporation.”

Member Power Supply Resources

Oglethorpe Power Corporation

In 2024, we supplied approximately 70% 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 “OUR BUSINESS – 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

Thirty-three of our members purchase hydroelectric power from the Southeastern Power Administration, or SEPA, under contracts that will continue until terminated by two years' written notice by SEPA or the respective member. At January 1, 2025, the aggregate SEPA allocation of capacity to the members was 570 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 EMC, has designated us to perform this function. Pursuant to a separate agreement, we schedule, through Georgia System Operations, our members' SEPA power deliveries. Further, each member may be required, if certain conditions are met, to contribute funds for capital improvements for 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 summer planning reserve capacity of 729 megawatts. The 35 members participating in these two facilities purchase the output of those facilities pursuant to separate take-or-pay

power purchase agreements that 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. As of December 31, 2024, Green Power EMC purchased energy from 820 megawatts of low-impact hydroelectric, landfill gas and solar facilities, with an additional 447 megawatts under contract and under construction, with plans to purchase more in the future. Included in this total is energy purchased from Green Power Solar, a for-profit subsidiary of Green Power EMC, which has leased, with an option to purchase, twelve solar facilities with a total of approximately 10 megawatts.

Other Member Resources

Our members obtain their remaining power supply requirements from various sources. All members are parties to requirements contracts or power purchase contracts that meet their incremental requirements. These contracts have remaining terms ranging from 1 to 20 years.

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 "OUR BUSINESS – Competition" and "OUR POWER SUPPLY RESOURCES – Recent and 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 a wide range of federal, state and local environmental laws. Air emissions, solid waste disposal, effluent 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 comprehensively regulated.

In general, environmental requirements applicable to the electric power sector are becoming increasingly prescriptive and stringent, and EPA finalized a number of rules in 2024 that could impact our power plants, even though the Trump administration has issued a number of executive orders and stated its intention to suspend, revise or rescind at least some of these requirements. Although we have installed an extensive array of environmental control systems at our plants to ensure continued compliance with all existing applicable requirements, including systems to reduce emissions of sulfur dioxide, nitrogen oxides, mercury and other regulated air pollutants, new environmental regulatory requirements could be imposed. Such additional requirements, if adopted, could substantially increase the cost of electric service by requiring modifications in the design or operation of existing facilities and making new facilities more difficult to site and more expensive to build. Failure to comply with these requirements could result in us becoming subject to enforcement actions and the assessment of civil penalties. In extreme cases of non-compliance, such enforcement actions could even include the complete shutdown of individual generating units. Certain of our debt instruments also 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 comply with these requirements, it would constitute a default under those debt instruments. Although we intend to comply with all current and future regulations, we cannot guarantee that we will always be in full compliance with every applicable requirement.

Our capital expenditures and operating costs continue to reflect expenses necessary to comply with all applicable environmental requirements and regulations. 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 regulations adopted at the federal and state levels have had and will continue to have a significant impact on the electric utility industry. The most significant environmental regulations for us continue to be the air regulatory requirements imposed under the Clean Air Act. These requirements include stringent regulations for controlling emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, greenhouse gases, and other air pollutants from affected electric utility units. The EPA has actively regulated emissions under the Clean Air Act and the following are the most significant ongoing Clean Air Act regulatory requirements that affect or may affect our business.

Controls for Meeting Air Quality Standards. Pursuant to the Clean Air Act, EPA sets National Ambient Air Quality Standards (NAAQS) for the following six air pollutants: particulate matter, ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide and lead. EPA is required to review the existing NAAQS every five years to determine whether a tightening of these standards is necessary to protect public health. On February 6, 2024, EPA published a final rule that lowered the current annual particulate matter (PM_{2.5}) standard from 12 parts per billion (ppb) down to 9 ppb but retained the existing 24-hour standards for certain particulate matter. This more stringent standard is likely to place additional geographic regions into nonattainment and could affect future siting decisions for new generation, as well as impose additional costs and potential operating restrictions. However, such regulatory determinations will not be made for several more years, and it is unclear how the EPA will proceed. The rule is being challenged in the U.S. Court of Appeals for the District of Columbia, and EPA requested a 60-day abeyance of the litigation on February 18, 2025, which was granted on February 25, 2025. As a result, we cannot determine the extent to which, if any, EPA’s tightening of the PM_{2.5} standard and the outcome of litigation and any regulatory changes, might have on Plant Scherer and our gas-fired generating units.

Generally speaking, while our coal-fired units at Plant Scherer have had control systems installed to reduce emissions and achieve current ambient air quality standards, the new finalized or any future revised NAAQS could lead to additional emissions reduction requirements. Costs of any additional or upgraded pollution control equipment or operating restrictions that could be required because of more stringent NAAQS cannot be determined at this time, neither can we determine such impacts on our coal or natural gas-fired generating units.

Air Quality Summary. We believe that the emission control systems currently installed at Plant Scherer and our natural gas-fired generating units are generally sufficient to meet the air quality requirements described above. However, the regulation of air emissions has been and is expected to continue to be fluid and additional emissions reduction requirements could be imposed on major sources within Georgia, including at our power plants, to remedy any local and interstate transport air quality problems. Subsequent developments, including litigation and new implementation approaches adopted by EPA and Georgia could require significant capital expenditures and increased operating expenses at certain of our generating facilities, particularly Plant Scherer.

Carbon Dioxide Emissions and Climate Change

Climate change policies will continue to influence federal and state legislative and regulatory decisions that affect the power sector. At the federal level, presidential administrations have held differing views on prioritizing actions to address climate change. Those differing views have led to swings in policies that create uncertainty about environmental requirements and associated impacts. Most recently, the Trump administration issued executive orders to withdraw the U.S. from the Paris Climate Agreement and revoke any attendant goals or commitments made by the Biden administration. Additionally, Executive Order 14514, “Unleashing American Energy,” directs the Administrator of the EPA, among other deregulatory actions, to make recommendations on the “legality and continuing applicability” of the 2009 Endangerment Finding, which forms the basis for EPA’s greenhouse gas regulations. On March 12, 2025, EPA announced 31 deregulatory actions it would be taking related to the “Unleashing American Energy” executive order, including reconsidering the 2009 Endangerment Finding and Clean Air Act section 111(b) and 111(d) regulations to limit power plant greenhouse gas emissions. We continue to

monitor climate change policies at both the federal and state level and anticipate continued instability and uncertainty, and we may need to make decisions even as policies shift from administration to administration.

Emissions of carbon dioxide from our fossil-fueled power plants totaled 9.9 million metric tons in 2024. Compared to 2005, our overall carbon dioxide emissions rate has declined by 41% through a combination of market factors, our commitment to running highly efficient units with lower carbon dioxide emissions rates and the retirement of Plant Wansley in 2022. From coal alone, our carbon dioxide emissions in 2024 declined by 64% compared to 2005.

In May 2024, EPA published final rule under Clean Air Act sections 111(b) and 111(d) to limit greenhouse gas emissions from new gas turbines and existing coal plants, respectively. This final rule replaces the Affordable Clean Energy Rule, which was vacated and remanded to EPA in 2021 by the U.S. Court of Appeals for the District of Columbia. As written, the final rule would likely adversely impact a portion of our coal and natural gas-fired generating units and have a significant impact on the U.S. power sector overall. Under the new rule, gas-fired turbines that operate above a 20% capacity factor are required to meet stringent carbon dioxide emissions standards, including adding carbon capture and sequestration (CCS) by January 1, 2032, for baseload units operating above a 40% capacity factor. Existing coal plants are required to either 1) cease operations by January 1, 2032, with no additional restrictions; 2) co-fire with 40% natural gas by January 1, 2030, and operate to January 1, 2039; or 3) reduce carbon dioxide emissions by 90% using CCS by January 1, 2032, to operate beyond January 1, 2039. However, the Trump administration has issued executive orders, among which include withdrawing from the Paris Climate Agreement and revoking any attendant carbon dioxide emissions goals and commitments, and stated its intention to rescind, revise or replace some existing environmental regulations, which would include regulations for greenhouse gas emissions from power plants. On March 12, 2025, EPA announced that it would reconsider regulations to limit greenhouse gas regulations from power plants. Additionally, EPA's final rule is being challenged in the U.S. Court of Appeals for the District of Columbia, and EPA recently requested on February 5, 2025, that the court withhold issuing an opinion and hold the case in abeyance for 60 days while EPA determines how it wishes to proceed. EPA's request for a 60-day abeyance was granted on February 19, 2025. Although we continue to evaluate the impact of EPA's greenhouse gas rule on our power plants, we cannot predict the outcome of any regulatory actions or the result of potential litigation challenging any of these actions.

Coal Combustion Residuals and Effluent Limitations Guidelines

In 2015, EPA established a comprehensive regulatory program to manage the disposal of coal combustion residuals (CCR) from coal-fired power plants as non-hazardous material under the Resource Conservation and Recovery Act (RCRA). The 2015 CCR rule sets forth 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 disposal facilities. Since 2015, EPA has made subsequent revisions to CCR requirements and, in 2022, EPA issued a number of proposed determinations on requests for extensions of time to close ash ponds. The proposed determinations could affect the Georgia Environmental Protection Division's (EPD) review of the proposed closure plans for the coal ash ponds at Plants Wansley and Scherer. We continue to monitor EPA's actions related to CCR; however, the ultimate impact is unknown at this time and subject to the outcome of ongoing litigation and any future EPA and Georgia regulatory actions.

In 2015, the EPA also finalized a rule to revise the effluent limitations guidelines (ELG) that apply to certain wastewater discharges from fossil fuel-fired steam electric power plants, including Plant Scherer. Since adopting the CCR and ELG rules, EPA has adopted revisions to the compliance deadlines and substantive requirements of the two rules, including a final supplemental ELG rule in May 2024, as discussed below. Similar to CCR requirements, we continue to monitor EPA's actions and ongoing litigation but cannot predict the ultimate impact of any outcomes at this time.

ELG Rule Changes. In 2017, EPA extended the ELG compliance deadlines set forth in the 2015 ELG rule to meet discharge limitations for scrubber wastewater and bottom ash transport water from affected coal-fired units, including Plants Scherer and Wansley to November 1, 2020. On November 22, 2019, EPA issued a proposed rule to

moderate the discharge limitations on these two wastestreams and subsequently published a final ELG reconsideration rule on October 13, 2020. The ELG rule extends the applicability date for scrubber waste water and bottom ash transport water to December 31, 2025, and allows for various subcategories based on planned future operations, including the rule's voluntary incentives program, low utilization, and early retirement of affected units. Units participating in any of the subcategories were required to submit a notice of planned participation.

The notice for Plant Scherer indicated that units 1 and 2 would comply with the ELG rule under the voluntary incentives program. For Plant Wansley the notice indicated that affected units would comply under the early retirement subcategory. The ELG rule allows for transferring between subcategories consistent with certain regulatory requirements, and the notices reserved the right to transfer subcategories if circumstances change.

In May 2024, the EPA published a final supplemental ELG rule, which generally increases the stringency of the wastewater discharge standards. Taken together, the ELG rule revisions are expected to increase capital and operating costs of affected units. However, because of the compliance strategy for Plant Scherer, we do not anticipate significant additional impacts related to more stringent requirements in the supplemental ELG rule. The 2024 supplemental ELG rule is being challenged in federal court and, on February 19, 2025, EPA requested a 60-day abeyance to determine how it wishes to proceed with the litigation. EPA's request for a 60-day abeyance was granted on February 28, 2025. Additionally, certain Trump administration executive orders direct EPA to develop and implement action plans that suspend, revise, or rescind certain environmental regulations. On March 12, 2025, EPA announced that it will reconsider the supplemental ELG rule. We continue to monitor EPA's actions related to ELG; however, the ultimate impact is unknown at this time and subject to the outcome of ongoing litigation and any future EPA regulatory changes.

CCR Rule Changes. In 2016, in response to EPA's CCR rulemaking, EPD adopted new requirements to regulate CCR wastes. These new rules incorporated EPA's requirements as well as state-only requirements for managing CCR wastes in Georgia. These state requirements were implemented and are enforced through a permit system that was approved by EPA in December 2019. Once CCR permits are issued by Georgia EPD, federal citizen suits under RCRA to enforce federal CCR requirements incorporated in the state permit are generally no longer allowed and permit challenges will be handled through EPD's existing administrative process. Georgia's existing CCR regulations are not anticipated to have a material impact on our compliance obligations under the federal CCR rule. However, we cannot predict the impact of any changes to Georgia's CCR regulations including potential legislation or litigation.

In 2019, Georgia Power ceased sending CCR to the ash ponds at Plants Scherer and Wansley. Similarly, Georgia Power has installed a new wastewater treatment system that will receive and manage the non-CCR wastestreams at Scherer. As a result, these new closure deadlines have not impacted our operations. Although no litigation related to CCR regulations is now pending, we cannot predict whether there will be any future lawsuits on the requirements for closing these impoundments or remedying any impacts the impoundments may be having on groundwater.

In 2018, Georgia Power applied for CCR permits to close the ash ponds at Plants Scherer and Wansley in place using advanced engineering methods. However, in March 2022, Georgia Power notified the Georgia Public Service Commission of a revised closure proposal for Plant Wansley. Georgia Power's modified closure plan at Plant Wansley recommends closure by removing the ash from the coal ash pond for several site-specific reasons, including available capacity at an existing on-site landfill due to the retirement of Plant Wansley in August 2022, beneficial use of the coal ash, and managing construction and operational risks of its current closure in place design. Georgia Power's proposed closure plans and any future revisions are subject to the approval of the Georgia Public Service Commission and EPD. Costs associated with the closure of ash ponds are reflected in the asset retirement obligations discussed below and we routinely update our asset retirement obligations to reflect any future changes in compliance requirements or cost projections. Georgia Power estimates closing activities to be completed in 2032 for both Plants Wansley and Scherer.

Since 2022, EPA has issued a number of proposed determinations on requests for extensions of time to close ash ponds. The proposed determinations include the agency's rationale and position at the time on closure standards, groundwater monitoring, and corrective action. In May 2024, EPA published a final CCR rule addressing legacy

coal ash surface impoundments with revised definitions related to coal ash. EPA's determinations and revised definitions could affect EPD's review of the proposed closure plans for Plants Wansley and Scherer under Georgia's CCR permit program. The final CCR rule is being challenged in the U.S. Appeals Court for the District of Columbia, and EPA recently requested a 120-day abeyance of the litigation on February 13, 2025. EPA's request was granted on February 14, 2025. Additionally, the Trump administration's recent executive orders and stated intention to rescind, revise or replace some existing environmental regulations could affect both the determinations and regulatory requirements. On March 12, 2025, EPA announced that it will be reviewing the final CCR rule. At this time, it is unclear how the Trump administration will address recent CCR regulatory actions or whether such actions will affect the current closure plans of coal ash ponds at Plants Wansley and Scherer. We continue to monitor EPA's actions related to CCR, however, the ultimate impact is unknown at this time and subject to the outcome of the litigation and any future EPA and Georgia regulatory actions.

Associated CCR and ELG Compliance Costs. We continue to evaluate the requirements associated with existing and future CCR and ELG rules. Based on this ongoing evaluation, we expect to periodically update compliance methods, schedules, and costs. Our current estimates for capital expenditures at Plant Scherer to comply with the applicable CCR requirements and effluent discharge limitations are estimated to be approximately \$230 million for conversion to dry ash handling, landfill construction, and wastewater treatment. This estimate includes \$170 million that has already been spent. Additionally, our current estimated expenditures for the settlement of related asset retirement obligations at our operating and retired coal plants are approximately \$600 million to \$800 million (in year of expenditure dollars) for the closure and post-closure of existing coal ash ponds and the dry coal ash and gypsum storage areas. Approximately \$70 million of this amount has already been incurred. See Note 1 of Notes to Consolidated Financial Statements in Appendix A. More definitive cost estimates will continue to be developed as the processes of rule evaluation, compliance approach and design and construction implementation proceed. The ultimate impacts associated with the federal and state CCR rules and the federal effluent discharge limitations, any revised regulation or legislation at the state or federal level and related litigation challenging such rules, or future legislation cannot be determined at this time. If Georgia's requirements for coal ash disposal are subsequently revised or the proposed closure plans are not approved, our estimated compliance costs could increase materially.

Water Use and Wastewater Issues

In 2015, the U.S. Court of Appeals for the Sixth Circuit stayed a final rule published jointly by EPA and the U.S. Army Corps of Engineers that revised the regulatory definition of waters of the U.S. for all Clean Water Act programs. The final rule would have significantly expanded the scope of federal jurisdiction under the Clean Water Act. Although the rule was not expected to have a substantial direct impact on our existing operations, it would likely have increased permitting and regulatory requirements and costs associated with the siting and permitting of new facilities. In July 2017, EPA and Army Corps of Engineers proposed a two-step process to address the stayed rule and followed that proposal with a supplemental proposed rule in June 2018. The first step replaced the 2015 regulations that defined waters of the U.S. with those that were in effect prior to the 2015 rule. In the second step, EPA proposed a rule in December 2018 replacing the 2015 definition with a revised definition that clarifies and narrows the scope of federal authority under the Clean Water Act. A final rule incorporating the proposed rules was issued on January 23, 2020. The EPA and Army Corps of Engineers subsequently revised the definition of waters of the U.S. in January 2023. However, in May 2023, the U.S. Supreme Court narrowed the definition of waters of the U.S., leading EPA and Army Corps of Engineers to issue a final rule on August 29, 2023, amending its definition to conform to the U.S. Supreme Court's decision. On March 12, 2025, EPA announced that it once again will be revising regulatory definitions of waters of the U.S. While there is minimal direct impact to our operations as a result of the current rule, we cannot determine the ultimate impact of any change to that rule or any litigation challenging various iterations of the rule or any replacement rule 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 the regulations implementing these environmental statutes. We do not believe that our compliance obligations with these statutory and regulatory requirements will have a material impact on our

financial condition or operation of our facilities. 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 any future actions on our business or facilities.

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 full compliance with all applicable 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 even force the complete shutdown of individual generating units not in compliance with these regulations in some cases. 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 Plant Hatch Units No. 1 and No. 2 expire in 2034 and 2038, respectively, and for Plant Vogtle Units No. 1, No. 2, No. 3 and No. 4 expire in 2047, 2049, 2062 and 2063, respectively. Southern Nuclear has notified the Nuclear Regulatory Commission of its intent to seek to renew Plant Hatch Units No. 1 and No. 2 licenses for an additional 20 years, through 2054 and 2058, respectively.

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 in Appendix A for information regarding settlements received as a result of and 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 depository 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, in June 2014.

We expect 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 in Appendix A. 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 in Appendix A.

Federal Power Act

General

Pursuant to the Federal Power Act, FERC 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 FERC 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 FERC. The currently effective FERC license to operate the Rocky Mountain project expires on December 31, 2026. We timely filed an application for a new license on December 6, 2024 that FERC accepted on March 3, 2025. See "PROPERTIES – Generating Facilities" and "– The Plant Agreements – Rocky Mountain" for additional information.

At this stage of the relicensing process, FERC will ensure the record is complete with respect to project information, conduct its environmental review, and then ultimately issue a new license order. FERC's grant of a new license to us could be subject to certain requirements that could result in additional costs and the timing of the new license issuance is not certain. However, if FERC does not act on the new license application prior to the expiration of the existing license, it 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 FERC 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. FERC certified the North American Electric Reliability Corporation, or NERC, as the electric reliability organization. The mandatory reliability standards developed by NERC and approved by FERC 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.

PROPERTIES

Generating Facilities

The following table sets forth certain information with respect to our generating facilities that operated for all or a portion of 2024.

Facilities	Type of Fuel	Percentage Interest	Our Share of Nameplate Capacity (megawatts)	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
Unit No. 3	Nuclear	30	363.3	2023	2062
Unit No. 4	Nuclear	30	363.3	2024	2063
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 ⁽²⁾
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⁾
BC Smith (near Savannah, Ga.)	Gas	100	597.0	2003	N/A ⁽¹⁾
Washington County (near Sandersville, Ga.)					
Unit No. 2	Gas	100	198.9	2003	N/A ⁽¹⁾
Unit No. 3	Gas	100	198.9	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⁾
Baconton (near Baconton, Ga.)					
Unit 500	Gas-Oil	100	58.9	2000	N/A ⁽¹⁾
Walton County	Gas	100	494.1	2001	N/A ⁽¹⁾
TA 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 FERC.

(2) In 2024, we submitted an application to extend this license.

Plant Performance

The following table sets forth certain operating performance information of each of our generating facilities operating as of December 31, 2024:

Unit	Summer Planning Reserve Capacity ⁽¹⁾ (Megawatts)	Equivalent Availability ⁽²⁾			Capacity Factor ⁽³⁾		
		2024	2023	2022	2024	2023	2022
Plant Hatch							
Unit No. 1	262.2	82 %	97 %	90 %	83 %	98 %	91 %
Unit No. 2	264.3	99	87	97	100	88	98
Plant Vogtle							
Unit No. 1	344.5	92	90	99	94	92	101
Unit No. 2	344.7	99	92	91	101	94	93
Unit No. 3 ⁽⁷⁾	335.1	79			78		
Unit No. 4 ⁽⁸⁾	335.1						
Plant Scherer							
Unit No. 1	515.0	92	98	78	38	45	38
Unit No. 2	515.0	79	94	93	29	15	15
Rocky Mountain ⁽⁴⁾							
Unit No. 1	272.3	81	97	91	13	17	16
Unit No. 2	272.3	71	90	96	14	17	20
Unit No. 3	272.3	98	89	76	14	14	10
Doyle ⁽⁴⁾	272.1	76	80	84	1	2	4
Talbot ⁽⁴⁾	675.6	77	76	75	8	8	10
Chattahoochee	484.5	75	90	67	67	82	59
BC Smith	527.0	63	90	77	35	56	55
Washington County ^(4,5)	326.0	78	93	100	11	1	0
Hawk Road ⁽⁴⁾	482.5	67	67	63	14	11	16
Hartwell ⁽⁴⁾	304.9	77	66	73	5	6	9
Baconton ^(4,6)	44.3	88	75		11	15	
Walton County ^(4,9)	449.7	63			15		
TA Smith							
Unit No. 1	647.3	94	94	92	72	75	68
Unit No. 2	647.3	91	93	94	76	77	71
TOTAL	8,594.0						

- (1) Summer Planning Reserve Capacity is the amount used for 2025 capacity reserve planning for the specified resources.
- (2) Equivalent Availability is a measure of the percentage of time a unit is available to generate if called upon, adjusted for periods when the unit is derated from its rated capacity.
- (3) Capacity Factor is a measure of the actual output of a unit as a percentage of its potential output.
- (4) Rocky Mountain, Doyle, Talbot, Hawk Road, Hartwell, Washington County, Baconton and Walton County, primarily operate as peaking plants, which results in low capacity factors.
- (5) Washington County was acquired in December 2022. This table only reflects operating performance following our acquisition. There was no generation during the month of December 2022. In 2024, Washington County's reserve capacity of 326.0 megawatts was partly unavailable in 2024 due to a power purchase and sale agreement with Georgia Power that expired May 31, 2024.
- (6) Baconton was acquired in May 2023. This table only reflects operating performance following our acquisition.
- (7) Plant Vogtle Unit No. 3 was placed in service on July 31, 2023. Plant Vogtle Unit No. 3's performance data was not available for 2023.
- (8) Plant Vogtle Unit No. 4 was placed in service on April 29, 2024. Plant Vogtle Unit No. 4's performance data has not been made available.
- (9) Walton County was acquired in June 2024. This table only reflects operating performance following our acquisition.

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

Fuel Supply

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 Scherer Units No. 1 and No. 2 is purchased under term contracts and in spot market transactions. As of February 28, 2025, our coal stockpile at Plant Scherer contained a 59-day supply based on continuous operation. Plant Scherer burns sub-bituminous coal purchased from coal mines in the Powder River Basin in Wyoming.

We dispatch our interest in Plant Scherer, but use Georgia Power as our agent for fuel procurement. As of December 31, 2024, we leased approximately 711 railcars to transport coal. Over the past few years, we have managed rail-related delays in connection with our coal supply.

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, BC Smith, Washington County, Baconton, Walton County, Hawk Road, Hartwell, and TA Smith. We purchase natural gas in the spot market and under agreements at market 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 have entered into long-term firm contracts for transportation of a significant percentage of our anticipated natural gas supply. We also purchase transportation under 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, and Scherer Units No. 1 and No. 2 are co-owned by Georgia Power, MEAG, 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. 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		Total MW ⁽¹⁾
	Plant Hatch		Plant Vogtle		Plant Scherer Units No. 1 & No. 2		Rocky Mountain		
	%	MW ⁽¹⁾	%	MW ⁽¹⁾	%	MW ⁽¹⁾	%	MW ⁽¹⁾	
Oglethorpe	30.0	539	30.0	1,423	60.0	982	74.6	633	3,577
Georgia Power	50.1	900	45.7	2,167	8.4	137	25.4	215	3,419
MEAG	17.7	318	22.7	1,076	30.2	494	—	—	1,888
Dalton	2.2	39	1.6	76	1.4	23	—	—	138
Total	100.0	1,796	100.0	4,742	100.0	1,636	100.0	848	9,022

(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 Savannah, as well as in rural areas, and at wholesale to some of our members, MEAG and two municipalities. Georgia Power is the largest supplier of electric energy in the State of Georgia. See “OUR BUSINESS – BUSINESS OVERVIEW – 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, 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 has wholesale take-or-pay power sales contracts with each of its 49 participants that extend to June 2054. MEAG 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.

The Plant Agreements

Plants Hatch, Vogtle and Scherer

Our rights and obligations with respect to Plants Hatch, Vogtle and Scherer are contained in a number of contracts between Georgia Power and us and, in some instances, MEAG and the City of Dalton. We are a party to three Purchase and Ownership Participation Agreements (Ownership Agreements) under which we acquired from Georgia Power a 30% undivided interest in each of Plants Hatch and Vogtle Units No. 1 and No. 2, 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 three Operating Agreements (Operating Agreements) relating to the operation and maintenance of Plants Hatch, Vogtle Units No. 1 and No. 2 and Scherer, respectively. The Ownership Agreement and Operating Agreement relating to Plant Hatch is a two-party agreement between Georgia Power and us. The Ownership Agreements and Operating Agreements relating to Plants Vogtle Units No. 1 and No. 2 and Scherer are agreements among Georgia Power, MEAG, 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.

We have a 30% undivided interest in Vogtle Units No. 3 and No. 4. In conjunction with the development of these units, we, Georgia Power, MEAG 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, and contract management.

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 and then leased back the 60% interest. 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 Appendix A. 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 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.

The Scherer Ownership Agreement requires the consent of participants owning at least an aggregate 75% undivided ownership interest in the applicable unit (effectively us and MEAG) for actions with respect to the retirement of all or any part of the applicable unit.

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 ownership and operating agreement allows 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.

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, 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 "OUR BUSINESS – REGULATION – Nuclear Regulation." The Operating Agreement for Scherer Units No. 1 and No. 2 expires on January 31, 2026 and automatically renews for additional two year terms subject to notice of termination provisions. 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.

Georgia Power's January 2025 integrated resource plan included, among other things, requests to approve upgrades to Plant Hatch Units No. 1 and No. 2 and Plant Vogtle Units No. 1 and No. 2, some of which would be available in 2028, that would increase our nameplate capacity by an aggregate of 70 megawatts (based on our 30% interest).

A decision from the Georgia Public Service Commission on Georgia Power's 2025 resource plan is expected in summer 2025. The ultimate outcome of these matters cannot be determined at this time.

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.

Employees

As of December 31, 2024, we had 379 employees.

LEGAL PROCEEDINGS

See Note 12 of Notes to Consolidated Financial Statements in Appendix A.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Overview

General

Our principal business is providing wholesale electric service to our 38 members in a reliable, safe and cost-effective manner. We serve approximately 70% of our members' power supply needs from our diverse portfolio of generating units that totals 8,594 megawatts of summer planning reserve capacity. Consequently, substantially all of our revenues and cash flow are derived from sales to our members pursuant to take-or-pay wholesale power contracts which extend until 2085. 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.

2024 Financial Results

We had another successful year in 2024 and continue to be well positioned, both financially and operationally, to fulfill our obligations to our members, bondholders and creditors.

In 2024, our operating revenues increased to nearly \$2.2 billion, and we sold over 32.0 million megawatt hours compared to \$1.7 billion in revenues and 29.7 million megawatt hours sold in 2023. In 2024, our revenues were more than sufficient to recover all of our costs and to satisfy our debt service obligations and financial covenants. Specifically, we recorded a net margin of \$70.5 million in 2024, 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. For 2025, following completion of the new Vogtle units, our board of directors elected to return our target margins for interest ratio to the pre-construction level of 1.10. Our cost-plus formulary rate structure ensures recovery of costs on a monthly basis, and we remain focused on delivering cost-effective, reliable power to our members rather than on maximizing revenues.

As a result of expanding our portfolio of generation resources through the completion of Vogtle Units No. 3 and No. 4 and the acquisition of multiple natural gas-fired generation resources and the upgrading of our existing generation facilities, our total assets and total debt have significantly increased over the past several years. At December 31, 2024, our total assets were \$16.5 billion and total long-term debt was \$12.6 billion. We are also constructing additional generation resources on behalf of our members which we expect to continue to increase our assets and long-term debt.

We have strategically financed and refinanced capital investments over the last several years with long-term debt through the Department of Energy and Rural Utilities Service loan guarantee programs, and taxable and tax-exempt capital markets offerings which have enabled us to borrow long-term debt at relatively low rates. Our weighted average interest cost on long-term debt was 3.99% per annum at December 31, 2024. We will continue to actively manage our debt portfolio and utilize advantageous borrowing programs available to us as our ability to borrow at lower costs ultimately benefits our members and their customers as interest savings are reflected in our pass-through rate structure.

Vogtle Units No. 3 and No. 4

On April 29, 2024, Vogtle Unit No. 4 achieved commercial operation following the successful commercial operation of Vogtle Unit No. 3 on July 31, 2023. These units have been a primary focus area, and the successful completion of Vogtle Unit No. 4 eliminated one of our most significant sources of cost uncertainty. As of December 31, 2024, our total investment in the additional Vogtle units was approximately \$8.3 billion. We are now recovering the costs of both Vogtle units in member rates, which is improving our financial metrics.

With the completion of both Vogtle Units No. 3 and No. 4, we are now supplying power from those units to our members which has increased the power we supply to our members and the wholesale power cost per kilowatt hour. In 2024, our average wholesale power cost for members sales remained under 7 cents per kilowatt hour even with the addition of the new Vogtle units. The increase in rates from the new Vogtle units is moderated by rate management programs we and several of our members put in place during the Vogtle construction period. Rate volatility and impacts on our members are also mitigated by our diversified portfolio of generating assets. Our members' average residential retail rates have historically been competitive with other Georgia utilities and are projected to remain competitive.

We are pleased with the successful commercial operation of Unit No. 3 and No. 4 and their initial operating performance. These units have an aggregate of approximately 2,400 megawatts of carbon-free, baseload generating capacity. We expect our interest in these units to be valuable assets for us and our members over the next 60 to 80 years and to contribute to our diverse pool of generation resources.

Load Growth in Georgia

Georgia is projected to experience a significant increase in energy demand over the next several years based on native load growth and large loads related to new data centers and manufacturing facilities. Large loads in Georgia are subject to competition for electric service, and some of our members have been selected to serve these large loads and may be selected for more. In addition to load growth, our member demand has experienced an increase in winter peaks which has created the need for additional natural gas resources, particularly when solar resources are not generating electricity.

As a result of these factors, our members have asked us to undertake the development and construction of two new natural gas-fired generation resources, which we and our members approved in 2024. One of the projects is an approximately 1,425-megawatt, two-unit combined cycle generation facility to be located on land we own adjacent to the Smarr Energy Facility in Monroe County, Georgia. Our expected budget for this project is approximately \$1.8 billion to \$2.3 billion. The other project is an approximately 240-megawatt combustion turbine unit to be constructed at our Talbot Energy Facility in Talbot County, Georgia. Our expected budget for this project is approximately \$360 million. We and our members have also approved 75 megawatts of utility-scale battery storage resources. Our budget for these batteries is approximately \$200 million to \$250 million which is expected to be offset by an \$81 million grant awarded under the Department of Energy's GRIP Program. Our members will continue to assess the potential impact of this load growth on their power supply needs and may evaluate additional resources from us or other third parties to meet additional demand.

Liquidity Position

Our strong liquidity position continues to be one of the most positive attributes contributing to our solid financial standing. 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 \$1.275 billion unsecured credit facility that we renewed in 2024 to extend through May 2029 and that supports our commercial paper program. Additionally, we have three other bank credit facilities which provide another \$450 million in credit commitments, including a \$200 million credit facility with J.P. Morgan Chase Bank which we recently renewed through March 2027.

In addition to our strong liquidity, we have multiple sources of long-term financing available to meet our anticipated capital needs. These sources include the Rural Utilities Service federal loan program and the taxable and tax-exempt capital markets. We expect to continue utilizing each of these sources of capital to meet our long-term financing needs in the coming years. We also have \$4.1 billion outstanding pursuant to borrowings under the Department of Energy loan program to finance the construction of the new Vogtle Units. We have also been awarded funds under the Department of Energy GRIP Program and the Rural Utilities Service Empowering Rural America (New ERA) program; however, receipt of funding under these programs is not certain and subject to the risk of federal administrative actions, meeting programmatic requirements and, in the case of the Rural Utilities Service New ERA loan, entering into final agreements.

Environmental Regulations

Another of our key focus areas is maintaining compliance with all applicable environmental laws and regulatory standards. We own electric generation facilities powered by nuclear, natural gas, coal and hydro resources, and complying with environmental regulations presents substantial challenges for us and our members. The continuing trend of presidential administrations rescinding or rewriting existing regulations, or adopting new regulations, creates an environment of instability and uncertainty in which we will need to make decisions. For example, recent Trump administration executive orders have directed EPA and other agencies to rescind, revise or replace regulations put in place by the Biden administration and create significant uncertainty regarding the outcome of several recently finalized environmental regulations and the broader environmental regulatory landscape. Additionally, stringent regulatory standards could require us to modify the design or operation of existing facilities and result in significant increases in the cost of electricity or decreases in the amount of energy (due to operational constraints) we provide to our members. As an electric cooperative that operates on a not-for-profit basis, our compliance costs are ultimately borne by our members' electricity consumers.

Greenhouse gas emissions, particularly carbon dioxide, are the focus of some of the recent federal environmental regulations and administrative actions. In January 2025, President Trump withdrew the United States from the Paris Climate Agreement, pursuant to which the prior administration had proposed economy-wide carbon dioxide reductions of 50-52% of 2005 levels by 2030. In order to meet that economy-wide goal, analyses indicate that the power sector would have to reduce carbon dioxide emissions by approximately 80% below 2005 levels by 2030. To that end, the EPA finalized a new rule in 2024 to address carbon dioxide emissions from existing coal and new natural gas-fired power plants. We believe that some of the assumptions used for the final rule, particularly regarding options to limit carbon dioxide emissions and the pace of technological advancements, are unrealistic. At this time, the future of the final rule is subject to significant uncertainty, and we cannot predict the outcome or potential cost of any legislative or regulatory changes on us or our members, but such costs could be significant.

We believe that we are well-situated to effectively manage such challenges. Our diverse asset base, along with our investment in additional carbon-free generation at Vogtle Units No. 3 and No. 4, recent additions of natural gas generation resources and the construction of new generation resources, position us well to continue to meet our members' needs. Further, our members continue to pursue renewable generation opportunities and invest where they deem appropriate in order to further diversify their power supply resources to meet the demands of their member consumers and prepare for potential future limitations on greenhouse gas emissions.

In addition to greenhouse gases, we must also comply with several other environmental regulations. For example, in order to comply with federal and state coal combustion residual rules and effluent limitations guidelines, we are investing approximately \$230 million in capital costs at Plant Scherer, of which \$170 million has already been spent, in addition to the current projection of \$600 million to \$800 million (in year of expenditure dollars) associated with our corresponding asset retirement obligations at our operating and retired coal plants. If existing laws or regulations related to the disposal of coal combustion residuals and treatment of coal ash ponds were to change or we are otherwise required to revise our existing closure plans, our related obligations could increase or decrease significantly.

Sustainable Business

As electric cooperatives, we and our members are committed to sustainable and long-term success for the benefit of the people we serve. We are focused on generating cleaner energy and have made strides toward improving the environment through reducing greenhouse gas emissions, including carbon. With respect to carbon, by the end of 2025, we are forecasting that the carbon intensity rate for the energy we generate for our members will decrease by 41% from 2005 levels.

In 2024, we supplied approximately 70% of our members' energy requirements from our diverse portfolio of nuclear, gas, coal and hydro resources. Green Power EMC, owned by our members and supported by Oglethorpe employees, specializes in the purchase of renewable energy for our members. As of December 31, 2024, Green Power purchased 820 megawatts of renewable energy resources and expects to grow to more than 1,267 megawatts

by the end of 2027. Our members also contract directly with renewable suppliers, and, by the end of 2027, we anticipate that our members' total solar portfolio will exceed 2,285 megawatts.

Electric cooperatives were created to bring electricity to underserved, rural areas and continue that mission today as our members serve many of the most economically disadvantaged areas of Georgia. As a not-for-profit cooperative, owned and governed by our members, we have a unique perspective on corporate governance. We were created by and exist to serve our members and our focus on members is part of who we are. More specifically, our members elect our board of directors and our equity is our members' patronage capital. The critical role that our members play in our business is reflected in the seven pillars of cooperative organizations: (i) voluntary and open membership, (ii) democratic member control, (iii) members' economic participation, (iv) autonomy and independence, (v) education, training and information, (vi) cooperation among cooperatives and (vii) concern for community.

We rely on our workforce for our success and embrace the diverse thoughts and perspectives they bring to us and our members. We have established a culture of high ethical and safety standards for our workforce, along with robust risk management and strategic planning processes to guide us through the transitioning energy landscape.

We are proud of our progress in these areas and continue to push ourselves to improve. Our commitment to these priorities goes beyond talking points. For several years, certain of the corporate goals that determine our executives' performance pay have been, and continue to be, directly related to environmental, worker safety and corporate governance metrics.

Outlook for 2025

As Georgia faces significant growth in electricity demand and as the electric utility industry across the country continues to experience change, we remain focused on providing reliable, safe, and cost-effective energy to our members and the 4.7 million people they serve. We believe we are well positioned to do so. As discussed above, there are certain risks and challenges that we must continue to address, most notably related to load growth in Georgia and continued federal environmental regulations. However, as we manage our risks, we intend to keep doing what we have done so successfully for more than 50 years, including, among other things:

- maintaining a balanced and diverse portfolio of generating resources, including nuclear, natural gas, coal and hydro and continuing the reliable, 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 to explore existing and emerging opportunities to add value to our ultimate consumers.

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 FERC 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, 2024, our regulatory assets and regulatory liabilities totaled \$1.1 billion and \$661.6 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 regulatory liabilities that had been recognized as a charge or credit 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 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 base year decommissioning costs 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, identifying which of our generation plants have a legal obligation, making projections for when our generation plants will be retired and ultimately decommissioned, estimating the decommissioning costs, and evaluating how costs will escalate with inflation. Actual results may differ from our estimates.

A significant portion of our asset retirement obligations relates to our share of the future cost to decommission our operating nuclear units and the coal ash ponds at our coal-fired units. At December 31, 2024, our nuclear decommissioning and coal ash related asset retirement obligations were \$812.2 million and \$403.2 million, respectively. Our asset retirement obligations represent an estimate of the present value of anticipated legally obligated retirement costs. For additional detail regarding our asset retirement obligations, see Note 1h of Notes to Consolidated Financial Statements in Appendix A. These obligations represented 95% of our total asset retirement obligations.

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 the amount and timing of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual costs. In addition, these estimates are dependent on subjective factors, including estimates computed by third party specialists in the nuclear regulatory environment, the selection of cost escalation, discount rates and assumed dates of decommissioning, which we consider to be critical assumptions. While evaluating the probability of the assumed dates of decommissioning, factors considered included, but were not limited to, examination of the nuclear unit's remaining operating and economic life, re-licensing expectations, and industry trends. Ultimately, the revised cost site studies reflected later assumed dates of decommissioning than the prior studies. Our current estimates are based upon studies that were performed in 2024. For ratemaking purposes, we record decommissioning costs over the expected useful life of each unit. The impact on measurements of asset retirement obligations using different assumptions in the future may be significant.

We also consider our coal ash related decommissioning liabilities to be critical estimates, in particular those for the coal ash ponds. Cost studies are periodically performed to provide site-specific “base year” estimates that determine the nature and timing of planned decommissioning costs. These cost studies are based on relevant information available at the time they are performed; however, estimates of the amount and timing of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual costs. Critical assumptions include the coal ash pond closure strategy, including water treatment requirements, and the volume of coal ash in the ponds. In addition, these estimates are dependent on other subjective factors, such as estimates of costs to perform the decommissioning and post-closure activities, timing of future cash outlays, and the selection of cost escalation and discount rates. Our current estimates are based upon studies that were performed in 2024. For ratemaking purposes, we are applying regulated operations accounting to the decommissioning costs and currently

expect to recover ash pond closure costs over approximately 10 years. The impact on measurements of asset retirement obligations using different assumptions in the future may be significant.

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. Our primary source of revenue is the sale of capacity and energy to our members for a portion of their energy requirements. We may also sell capacity and energy to non-members. Capacity revenues are the revenues we receive for providing 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 that we generate or purchase.

We have assigned fixed percentage capacity cost responsibilities to our members for all of our generation 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. 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 and our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights. In addition, as we do not provide our members with all of their energy requirements, energy sales may also fluctuate based on our 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. Variable costs are passed through to our members 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 “OUR BUSINESS – BUSINESS OVERVIEW – 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. Following the completion of Vogtle Unit No. 4, our board returned the approved margins for interest ratio of 1.10 for 2025. 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, 2024, we had \$1.3 billion 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 9.5% and 9.4% at December 31, 2024 and 2023, respectively.

Patronage capital is allocated to each of our members on the basis of their fixed percentage capacity cost 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 “OUR BUSINESS – BUSINESS OVERVIEW – 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 “OUR BUSINESS – BUSINESS OVERVIEW – 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.

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 in Appendix A.

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.

The types of generation assets we own include six nuclear units, three combined cycle natural gas-fired plants, several natural gas-fired simple cycle combustion turbine plants, a plant that burns sub-bituminous coal, and a pumped storage hydroelectric plant.

In 2024, the Vogtle Unit No. 4 nuclear generating resource achieved commercial operation, our 30% share of which represented 363 megawatts of nameplate capacity, as constructed. We also acquired the Walton County Power Plant, a three-unit 450-megawatt natural gas-fired combustion turbine facility. These resources continued to add to our already diverse mix of generation and fuel types among our power plants.

Decisions to dispatch our power plants and thus the amount of energy we generate and sell to our members are economically driven by supply and demand considerations. The primary supply considerations include (i) fuel prices and other marginal operating costs of the plant, which factor into a dispatch cost we calculate for each resource, (ii) plant availability, which is driven by factors such as outages for maintenance or refuelings and (iii) plant efficiency, as determined by the heat rate which measures the amount of fuel required to generate one kilowatt hour of electricity. We prioritize the order in which we typically 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. This 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 approximately a third of the energy they purchase.

In 2024, weather was a significant factor. The summer experienced extremely hot weather and winter was below normal. In 2023, weather was also a significant factor. The summer experienced extremely hot weather during the last half of August that led to a new all-time summer peak demand for our members. As a result, the amount of energy (in megawatt-hours) we generated and sold to members was higher than in 2022, and led to higher utilization of our combined cycle generating facilities and our coal facilities compared to the prior year. While the amount of energy we sold to our members was higher, our members' overall energy demand was lower in 2023 compared to 2022 primarily due to 2023 being a mild weather year. December 2022 still holds the overall peak when we experienced extremely cold weather.

In addition to member demand, we sell power from some of our generating resources off-system, typically from assets we acquire in advance of some members needing the capacity or energy. These members elect to defer their portion of the resource, and the output of the resource is sold to non-members which helps reduce deferred costs for these deferring members. We dispatch the majority of the BC Smith combined cycle facility to serve non-member sales, and we plan to continue doing so through 2027. In 2024, BC Smith underwent a major maintenance outage during the first half of 2024, therefore, we generated and sold fewer megawatt-hours of off-system energy from BC Smith compared with 2023. In 2023, we saw reduced market demand for these off-system sales compared with 2022; therefore, we generated and sold fewer megawatt-hours of off-system energy from BC Smith compared with 2022.

Fuel cost is our most significant operating cost. As our rate structure directly recovers costs through revenues, fuel prices greatly impact the cost of energy sold to our members and our member sales (in dollars). The price of natural gas is the most significant variable in our cost of fuel and also affects how we dispatch our generation resources. The first full year of commercial operation of Vogtle Unit No. 3, which began in July 2023, and commercial operation of Vogtle Unit No. 4, which began in April 2024, primarily contributed to the increase in fuel costs and megawatt-hour sales to the members in 2024. Offsetting the increase in fuel costs, we recorded a decrease in fuel costs for the settlement of two claims related to spent nuclear fuel storage costs. In 2023, natural gas prices decreased significantly compared with 2022 due to market alleviation of supply and demand pressures. This

decrease in natural gas prices led to more generation and sales to our members and lower fuel cost compared to 2022. The commercial operation of Vogtle Unit No. 3 also contributed to the increase in megawatt-hour sales to the members in 2023.

In addition to the prevailing market price, our average cost of natural gas per kilowatt-hour generated is also affected by how efficiently our natural gas facilities operate. Compared to our combustion turbine units, our combined cycle units are more efficient and burn less gas per kilowatt hour of electricity generated. Consequently, our combustion turbine units have a higher dispatch cost than our combined cycle units and are typically used to generate energy only during periods of higher electricity demand, such as hot summer days or colder winter days. In 2024, two of our combined cycle units underwent major maintenance outages which resulted in lower generation from our combined cycle units compared to 2023. And although 2023 had milder weather overall, more extreme weather days in 2023 resulted in significantly higher generation from our combined cycle units compared to 2022 and which also contributed to higher member sales (in megawatt-hours) in 2023, than in 2022.

Our nuclear units require refueling on an 18 or 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 periods that the plants were not generating power. In 2024, generation from the new units at Plant Vogtle offset the decrease in generation from Plant Hatch Unit No. 1. In 2023, generation from Vogtle Unit No. 3 offset the decrease in generation from the other nuclear units.

We also continued to make significant capital expenditures over the past three years, particularly for the new units at Plant Vogtle and the BC Smith, Washington County, Baconton and Walton County acquisitions, which we have primarily financed with debt. Financing these capital expenditures has 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 generally increased.

Net Margin

Our net margin for the years ended December 31, 2024, 2023 and 2022 was \$70.5 million, \$65.8 million and \$61.7 million, respectively. These amounts produced a margins for interest ratio of 1.14 in each of 2024, 2023 and 2022. 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. These revenues 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 the sales of electricity generated or purchased 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)			2024 vs. 2023	2023 vs. 2022
	2024	2023	2022	% Change	% Change
Capacity revenues	\$ 1,501,903	\$ 1,082,368	\$ 984,036	38.8 %	10.0 %
Energy revenues	643,619	599,198	990,647	7.4 %	(39.5)%
Total	\$ 2,145,522	\$ 1,681,566	\$ 1,974,683	27.6 %	(14.8)%
kWh Sales to members ⁽¹⁾	31,001,082	28,289,147	25,634,984	9.6 %	10.4 %
Cents/kWh	6.92	5.94	7.70	16.5 %	(22.8)%
Member energy requirements supplied ⁽¹⁾	70 %	68 %	58 %	2.9 %	17.2 %

(1) For 2024 and 2023, excludes test energy kilowatt-hours from Plant Vogtle Units No. 3 and No. 4 supplied to members. Any revenues and costs associated with test energy were capitalized.

Capacity revenues increased in 2024 compared to 2023 primarily due to Plant Vogtle Unit No. 4 being placed in service and the related recovery of net interest and depreciation expense. The increase in capacity revenues in 2023 compared to 2022 was due primarily to Plant Vogtle Unit No. 3 being placed in service and the related recovery of net interest and depreciation expense. For a discussion of production costs and depreciation expense, see “– Operating Expenses.”

The 7.4% increase in energy revenues from members in 2024 compared to 2023 was primarily a result of a 9.6% increase in generation for member sales offset by a decrease in energy revenues due to proceeds from the spent nuclear fuel storage costs litigation settlement. Upon recognition of the settlement, we recorded a \$34.4 million reduction in fuel expense and a corresponding decrease in member energy revenues. For additional information regarding spent nuclear fuel storage costs litigation, see Notes 1e and 1g of Notes to Consolidated Financial Statements in Appendix A. Energy revenues from members in 2023 compared to 2022 decreased 39.5% primarily a result of a decrease in total fuel expense offset by a 10.4% increase in generation for member sales. For a discussion of fuel expense, see “– Operating Expenses.”

Sales to non-members. In 2024 and 2023, energy revenues from non-members were primarily from the sale of the BC Smith deferring members' output into the wholesale market. Energy revenues from non-members decreased in 2024 from 2023 due to a decrease in megawatt-hours sold offset by an increase in fuel costs for natural gas. Energy revenues from non-members decreased in 2023 from 2022 due to a decrease in megawatt-hours sold and a decrease in fuel costs for natural gas. In 2024, 2023 and 2022, we recognized capacity revenues from non-members related to a tolling agreement associated with the two units we acquired at the Washington County Power Plant in 2022. This tolling agreement with Georgia Power expired in May 2024.

Sales to non-members were as follows:

	(in thousands)		
	2024	2023	2022
Energy revenues	\$ 34,753	\$ 44,995	\$ 155,372
Capacity revenues	1,572	13,624	82
Total	\$ 36,325	\$ 58,619	\$ 155,454
kWh Sales to non-members	1,048,865	1,415,042	1,690,454
Cents/kWh	3.46	4.14	9.19

Operating Expenses

Our operating expenses increased 16.1% in 2024 compared to 2023 primarily due to significantly higher production costs and higher depreciation and amortization expenses. In 2023 compared to 2022, operating expenses decreased primarily due to significantly lower fuel costs for natural gas as well as decreased production costs.

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

Fuel Source	Cost (dollars in thousands)					Generation ⁽¹⁾ (kWh in thousands)					Cents per kWh				
	2024	2023	2022	2024 vs. 2023 %	2023 vs. 2022 %	2024	2023	2022	2024 vs. 2023 %	2023 vs. 2022 %	2024	2023	2022	2024 vs. 2023 %	2023 vs. 2022 %
				Change	Change				Change	Change				Change	Change
Coal	\$ 138,682	\$ 124,638	\$ 107,207	11.3 %	16.3 %	3,501,003	3,166,368	2,856,494	10.6 %	10.8 %	3.96	3.94	3.75	0.6 %	11.3 %
Nuclear	115,825	84,192	73,871	37.6 %	14.0 %	14,219,693	11,122,301	10,206,060	27.8 %	9.0 %	0.81	0.76	0.72	7.6 %	(4.8)%
Nuclear Fuel Credits ⁽²⁾	(34,400)	—	—	N/M	N/M	—	—	—	N/M	N/M	N/M	N/M	N/M	N/M	N/M
Natural Gas:															
Combined Cycle	321,268	323,614	704,809	(0.7)%	(54.1)%	13,095,458	14,804,306	13,100,271	(11.5)%	13.0 %	2.45	2.19	5.38	12.2 %	76.8 %
Combustion Turbine	71,065	46,350	159,202	53.3 %	(70.9)%	2,058,663	1,382,989	1,824,570	48.9 %	(24.2)%	3.45	3.35	8.73	3.0 %	(61.6)%
	\$ 612,440	\$ 578,794	\$ 1,045,089	5.8 %	(44.6)%	32,874,817	30,475,964	27,987,395	7.9 %	8.9 %	1.86	1.90	3.73	(1.9)%	(49.1)%

(1) Excludes test energy megawatt-hours generated at Plant Vogtle Units No. 3 and No. 4.

(2) Represents credits to fuel expense for settlements related to spent nuclear fuel storage costs. For additional information regarding spent nuclear fuel storage costs litigation, see Notes 1e and 1g of Notes to Consolidated Financial Statements in Appendix A.
N/M - Not meaningful

Fuel

Total fuel expense increased in 2024 compared to 2023 as a result of an overall increase in generation. The increase in generation was primarily due to an increase in sales to our members as a result of the commercial operation of Vogtle Units No. 3 and No. 4 and our members obtaining more of their energy requirements from us due to relative energy prices. The decrease in average fuel cost was primarily due to the spent nuclear fuel storage costs litigation proceeds and lower average natural gas prices in 2024. For additional information regarding spent nuclear fuel storage costs litigation, see Notes 1e and 1g of Notes to Consolidated Financial Statements in Appendix A. In 2024 and 2023, we included \$24.3 million and \$20.9 million of net losses recognized, respectively, in total fuel expense for the settlement of natural gas financial contracts we utilized to manage our exposure to fluctuations in market prices. Total fuel expense decreased in 2023 compared to 2022 primarily as a result of a decrease in the average cost of fuel. The decrease in average fuel cost was primarily due to lower average natural gas prices in 2023. The overall increase in generation in 2023 compared to 2022 was due in part to an increase in sales to our members as a result of the commercial operation of Vogtle Unit No. 3 and our members obtaining more of their energy requirements from us due to relative energy prices.

Production

Production costs can vary due to the number and extent of outages in a given year. Production costs increased 26.9% in 2024 compared to 2023 and decreased 11.8% in 2023 compared to 2022. The increase in 2024 was due to higher fixed major maintenance outage costs associated with our combined cycle plants and the result of deferring BC Smith's effects on net margin during 2024 compared to 2023. Production costs also increased as a result of higher production costs related to Plant Vogtle Units No. 3 and No. 4. Production costs for the new Vogtle units are net of \$72.6 million in credits recognized in 2024 from the sale of nuclear production tax credits to Georgia Power. The decrease in 2023 was due to less costly planned major maintenance outages during 2023 compared to 2022.

Depreciation and amortization

Depreciation and amortization expense increased 24.6% in 2024 compared to 2023 primarily as a result of higher depreciation expense related to Vogtle Units No. 3 and No. 4 being placed in service on July 31, 2023 and April 29, 2024, respectively. Depreciation and amortization expense increased in 2023 compared to 2022 primarily as a result of higher depreciation expense related to Vogtle Unit No. 3 being placed in service.

Other Income

The 16.9% decrease in other income in 2024 compared to 2023 was primarily due to lower interest income as a result of lower average balances of commercial paper investments held in 2024 compared to 2023. Total other income was higher in 2023 compared to 2022 primarily due to higher interest income as a result of higher interest rates.

Interest Charges

Interest expense increased in 2024 primarily due to refinancing of commercial paper with higher-interest-rate long-term taxable bonds in December 2023 and in June 2024, and as a result of higher interest rates on the commercial paper in 2024 compared to 2023. The commercial paper that we refinanced with these bond issues was used as interim financing for Plant Vogtle Units No. 3 and No. 4 construction expenditures, and for interim refinancing of Department of Energy-guaranteed loan repayments made prior to the commercial operation of Vogtle Unit No. 4. Allowance for debt funds used during construction decreased in 2024 due to Vogtle Units No. 3 and No. 4 being placed in service. As a result of these factors, net interest charges increased 64.3% in 2024. Net interest charges increased in 2023 compared to 2022 primarily due to higher interest rates on commercial paper and the allowance for debt funds used during construction decreased due to Vogtle Unit No. 3 being placed in service.

Financial Condition

Overview

Consistent with our budgeted margin for 2024, we achieved a 1.14 margins for interest ratio which produced a net margin of \$70.5 million. This net margin increased our total patronage capital (our equity) and membership fees to \$1.3 billion at December 31, 2024. Our 2025 budget targets a 1.10 margin for interest ratio.

Our equity to total capitalization ratio, as defined in our first mortgage indenture, was 9.5% at December 31, 2024 and 9.4% at December 31, 2023. We anticipate that our equity ratio will remain around its current level during the next several years due to the new generation construction and will subsequently increase after we complete the bulk of the long-term financing for the new generation units; however, the absolute level of patronage capital will continue to increase.

We had a strong liquidity position at December 31, 2024 with \$1.7 billion of unrestricted available liquidity, including \$337.8 million of cash and cash equivalents. We issued commercial paper throughout the year to provide interim financing for the Plant Vogtle construction, the Walton County acquisition and for other general purposes. The average cost of funds on the \$400.1 million of commercial paper outstanding at December 31, 2024 was 4.8%.

Electric plant in service increased by approximately \$3.3 billion with a corresponding decrease in construction work in progress, primarily due to Vogtle Unit No. 4 being placed in service. The other capital additions include costs related to the Walton County acquisition, normal additions and replacements to existing generation facilities and purchases of nuclear fuel. For the past several years, our total assets have significantly increased primarily due to the additional nuclear units at Plant Vogtle.

Nuclear decommissioning trust fund increased \$80.4 million primarily due to the increase in investment income due to continued appreciation in the stock market in 2024. The nuclear decommissioning trust fund has produced an average annualized return for Plant Hatch Units No. 1 and No. 2 and Plant Vogtle Units No. 1 and No. 2 of approximately 6.7% in the last ten years and 6.4% since inception in 1990. The nuclear decommissioning trust fund has produced an average annualized return for Plant Vogtle Units No. 3 and No. 4 of approximately 21.0% since inception in 2022.

Long-term investments decreased primarily due to redemptions associated with our revenue deferral rate management plan, which was designed primarily to assist our members in managing the rate impacts associated with the new Vogtle units, and to fund major maintenance outages expenses. Largely offsetting these decreases was an increase in funds invested, including reinvestment of earnings, and an increase in fair market value of investments.

See Notes 1e and 1q of Notes to Consolidated Financial Statements in Appendix A for a discussion of our member rate management programs and regulatory liabilities.

Receivables increased \$44.8 million at December 31, 2024 compared to December 31, 2023. The net increase was primarily due to a \$41.3 million increase in receivables from Georgia Power related to a settlement receivable for spent nuclear fuel storage costs litigation proceeds.

Prepayments and other current assets increased \$25.9 million at December 31, 2024 compared to December 31, 2023. The net increase was primarily due to a \$18.0 million increase in fair value of our natural gas contracts that will settle within the next twelve months.

Regulatory assets decreased by \$27.9 million at December 31, 2024 compared to December 31, 2023. The net decrease was primarily due to the decrease in the deferral associated with coal ash pond asset retirement obligations. This decrease was offset by an increase in the BC Smith deferral as that facility underwent a major maintenance outage in 2024 which resulted in decreased sales into the wholesale market.

Long-term debt and long-term debt and finance leases due within one year increased by \$547.8 million at December 31, 2024 compared to December 31, 2023. The net increase was primarily a result of the issuance of \$350.0 million of our Series 2024A green first mortgage bonds, \$317.5 million in advances under Rural Utilities Service-guaranteed loans, and reclassifying \$254.5 million of commercial paper to long-term debt that was refinanced through the issuance of the Series 2025A green first mortgage bonds in January 2025. Offsetting these increases was \$375.4 million in debt service payments. The weighted average interest rate on the \$12.6 billion of long-term debt outstanding at December 31, 2024 was 3.95%.

Short-term borrowings, which primarily provided interim financing for Vogtle Units No. 3 and No. 4 construction costs, decreased \$462.3 million at December 31, 2024 compared to December 31, 2023, primarily as a result of repayments of \$494.5 million.

Asset retirement obligations decreased \$179.8 million at December 31, 2024 compared to December 31, 2023. The net decrease was primarily due to change in cash flow estimates of \$235.2 million and \$55.6 million for nuclear decommissioning costs and coal ash related decommissioning costs, respectively, and approximately \$23.3 million of settled liabilities, offset by \$69.2 million in accretion expense and recognized nuclear asset retirement obligations of \$65.1 million due to Vogtle Unit No. 4's nuclear reactor achieving self-sustaining nuclear fission.

Regulatory liabilities decreased by \$44.7 million at December 31, 2024 compared to December 31, 2023. The net decrease was primarily due to a \$111.1 million decrease in the liability for our revenue deferral rate management plan, which is associated with the new Vogtle units, and a net \$20.6 million decrease in the liability for collections of future major maintenance outage costs. Offsetting these decreases was a \$55.6 million increase in deferred nuclear asset retirement obligations that was primarily driven by an increase in unrealized gains associated with our nuclear decommissioning investments, and a \$16.3 million increase in the liability for collections of future debt service payments.

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. See “– *Capital Requirements – Capital Expenditures*” for more detailed information regarding our estimated capital expenditures.

We have fully drawn \$4.6 billion of loans from the Federal Financing Bank that are guaranteed by the Department of Energy to fund a portion of our cost to construct the two new nuclear units at Plant Vogtle. As of December 31, 2024, we had \$4.1 billion outstanding.

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. We continue to utilize these loans for general and environmental improvements, and we have utilized these loans to provide a portion of the long-term financing for the BC Smith, Washington County and Baconton acquisitions and related costs. We plan to utilize these loans to

provide long-term financing for the Walton County acquisition and related costs and for our two new natural gas generation resources. However, Rural Utilities Service funding levels for projects we may choose to undertake are uncertain and may be limited 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. If the Rural Utilities Service loan program were to be curtailed or eliminated, we believe we are well positioned to continue to access capital market financings. See “– Financing Activities” for more detailed information regarding our financing plans.

See “OUR BUSINESS – BUSINESS OVERVIEW – Relationship with Federal Lenders” for further discussion of our relationship with the Department of Energy and Rural Utilities Service. See Note 7 in Notes to Consolidated Financial Statements in Appendix A for additional information regarding these loans.

Liquidity. At December 31, 2024, we had \$1.7 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of \$337.8 million of cash and cash equivalents and \$1.32 billion of unused and available committed credit arrangements.

Net cash provided by operating activities was \$428.9 million in 2024, and averaged \$389.9 million per year for the three-year period 2022 through 2024.

In May 2024, we amended our syndicated line of credit among eleven lenders, including National Rural Utilities Cooperative Finance Corporation, as administrative agent, to extend the maturity date for five years to May 2029. In connection with this amendment, we increased the available amount under the credit agreement to \$1.275 billion from \$1.21 billion. In September 2024, we amended our JPMorgan Chase Bank, N.A. line of credit facility to extend the maturity date to March 2027. In connection with this amendment, we decreased the available amount under the credit agreement to \$200 million from \$350 million.

At December 31, 2024, we had \$1.725 billion of committed credit arrangements in place and \$1.32 billion available under four separate credit facilities. These are reflected in the table below:

Committed Credit Facilities				
(dollars in millions)				
	Authorized Amount	Available 12/31/2024	Expiration Date	
Unsecured Facilities:				
Syndicated Line among 11 banks led by CFC ⁽¹⁾	\$ 1,275	\$ 873	May 2029	
CFC Line of Credit ⁽²⁾	110	110	December 2028	
JPMorgan Chase Line of Credit ⁽³⁾	200	197	March 2027	
Secured Facilities:				
CFC Term Loan ⁽²⁾	250	140	December 2028	

⁽¹⁾ This facility is dedicated to support outstanding commercial paper and the portion of this facility that was unavailable represents outstanding commercial paper at December 31, 2024.

⁽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. Therefore, we reflect \$140 million as the amount available under the term loan even though there are no amounts outstanding under that facility. 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⁾ At December 31, 2024, \$2.5 million of this facility was used for letters of credit issued to provide performance assurance to third parties.

We have the flexibility to use the \$1.275 billion syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up commercial paper.

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

under the \$1.3 billion syndicated line of credit. At December 31, 2024, our outstanding commercial paper primarily was used to provide interim funding for:

- payments related to the construction of Vogtle Units No. 3 and No. 4,
- principal payments made under our Department of Energy-guaranteed loans prior to the commercial operation of Vogtle Unit No. 4,
- costs related to the Walton County acquisition,
- costs related to the deferral of effects on net margin of our recently acquired facilities: BC Smith, Baconton, Washington County and Walton County, and
- costs related to the new Smarr Combined Cycle and Talbot Unit No. 7 projects.

Rural Utilities Service financing is our preferred source of long-term financing for the Walton County acquisition, and for the Smarr Combined Cycle and Talbot Unit No. 7 projects. In January 2025, we issued \$350 million of 5.90% Series 2025A Green First Mortgage bonds which we used to refinance all of the commercial paper related to the construction of Vogtle Units No. 3 and No. 4, and principal payments made under our Department of Energy-guaranteed loans. We intend to issue first mortgage bonds to provide long-term financing for certain other costs, including any costs for the Smarr Combined Cycle and Talbot Unit No. 7 projects not financed by the Rural Utilities Service, and for the deferral of effects on net margin of our recently acquired facilities.

Our unsecured committed lines of credit permit the issuance of up to \$810 million in letters of credit on our behalf, of which \$807 million remained available at December 31, 2024. This letter of credit issuance capacity includes \$500 million under our \$1.275 billion syndicated line of credit, \$200 million under our JPMorgan Chase line of credit, and \$110 million under our CFC line of credit. 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 natural gas resources, until long-term financing is obtained.

Three of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At December 31, 2024, the highest required minimum level was \$900 million and our actual patronage capital balance was \$1.3 billion. Two of these agreements contain an additional covenant that limits our unsecured indebtedness, as defined in the credit agreements, to \$4 billion. At December 31, 2024, we had \$400.1 million of unsecured indebtedness outstanding.

Under our power bill prepayment program, members can prepay their power bills from us at a discount for an agreed number of months in advance, after which point the funds are credited against the participating members' monthly power bills. At December 31, 2024, we had five members participating in the program and a balance of \$85.4 million remaining to be applied against future power bills.

Liquidity Covenants. At December 31, 2024, 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 2024 and expect to have sufficient liquidity to meet this covenant in 2025. For a discussion of the Rocky Mountain lease transaction, see Note 4 of Notes to Consolidated Financial Statements in Appendix A.

Financing Activities

First Mortgage Indenture. At December 31, 2024, we had \$12.4 billion of outstanding debt secured equally and ratably under our first mortgage indenture, an increase of \$292.1 million from December 31, 2023. 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. As of December 31, 2024, the amount of certified bondable additions and retired

or defeased first mortgage indenture obligations available for the issuance of additional first mortgage indenture obligations was approximately \$3.4 billion. In addition, as of December 31, 2024, we had \$308.9 million of property additions and certified progress payments under qualified engineering, procurement and construction contracts that, once certified in accordance with the first mortgage indenture, will be available for the issuance of additional first mortgage indenture obligations.

Department of Energy-Guaranteed Loans. We have loans from the Federal Financing Bank guaranteed by the Department of Energy to provide funding for over \$4.6 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. By the end of 2022, we had fully advanced the \$4.6 billion available under the Department of Energy-guaranteed loans. In accordance with the related promissory notes, we began principal repayments of these loans in February 2020. As of December 31, 2024, we had repaid \$582.4 million under these loans and \$4.1 billion remained outstanding. All of the debt advanced under the loan guarantee agreement is secured ratably with all other debt under our first mortgage indenture. For additional information regarding these loans, see Note 7a of Notes to Consolidated Financial Statements in Appendix A.

In addition, we have raised \$3.6 billion of debt in the capital markets to finance our costs related to the construction of Vogtle Units No. 3 and No. 4 including a portion of the \$486 million of the principal payments under the Department of Energy-guaranteed loans repaid before the in-service date of Vogtle Unit No. 4.

Rural Utilities Service-Guaranteed Loans. A summary of our current Rural Utilities Service-Guaranteed Loans as of December 31, 2024 is provided in the table below:

Current Rural Utilities Service-Guaranteed Loans			
	Amount Approved	Amount Advanced December 31, 2024	Amount Remaining December 31, 2024
	(dollars in millions)		
General and Environmental Improvements	\$ 630.3	\$ 460.6	\$ 169.7
General and Environmental Improvements	755.2	187.3	567.9
Washington County Acquisition	87.9	87.9	—
Baconton Acquisition	17.5	17.5	—
Total	\$ 1,490.9	\$ 753.3	\$ 737.6

In 2024, we borrowed \$317.5 million under various Rural Utilities Service-guaranteed loans. This included full advances for the Washington County and Baconton acquisition loans and a \$187.3 million advance on the \$755.2 million general and environmental improvements loan. When advanced, the debt will be secured ratably under our first mortgage indenture. As of December 31, 2024, we had \$2.8 billion of debt outstanding under various Rural Utilities Service-guaranteed loans, an increase of \$132.9 million from December 31, 2023.

In December 2024, the Rural Utilities Service announced a \$331 million award to us under its Empowering Rural America (New ERA) program. The award would be used to refinance outstanding debt associated with the retired Hal B. Wansley coal plant, which will result in interest expense savings that will be passed to our members. The final amount and availability of any award is subject to uncertainty regarding the New ERA program, entering into binding agreements with the Rural Utilities Service and meeting program requirements.

All of the approved Rural Utilities Service-guaranteed loans are funded through the Federal Financing Bank, and the debt is secured ratably with all other debt under our first mortgage indenture.

Bond Financings. In June 2024, we issued \$350 million of 5.80% Series 2024A green first mortgage bonds, to provide long-term refinancing of the principal repayments of our Department of Energy-guaranteed loans that occurred before the in-service date of Vogtle Unit No. 4. These bonds are due to mature in June 2054 and are secured under our first mortgage indenture. In January 2025, we issued \$350 million of 5.90% Series 2025A green first mortgage bonds, Series 2025A, to provide long-term refinancing of the principal repayments of our Department of Energy-guaranteed loans that occurred before the in-service date of Vogtle Unit No. 4, and for expenditures related to the construction of Vogtle Units No. 3 and No. 4. These bonds are due to mature in February 2055 and are

secured under our first mortgage indenture. With these financings, we have substantially completed our long-term funding for Vogtle Units No. 3 and No. 4.

Capital Requirements

Cash Requirements. Our cash requirements relate primarily to operating expenses, capital expenditures and debt service. As discussed under “– Sources of Capital and Liquidity,” we fund our cash requirements through a mix of funds generated from operations and short- and long-term borrowings. For additional information regarding our contractual commitments, see Note 11 of Notes to Consolidated Financial Statements in Appendix A.

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 2025 through 2027. 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)				
	2025	2026	2027	Total
Future Generation ⁽²⁾	\$ 291	\$ 418	\$ 550	\$ 1,259
Existing Generation ⁽³⁾	548	282	316	1,146
Environmental Compliance ⁽⁴⁾	30	34	16	80
Nuclear Fuel	124	139	127	390
General Plant	14	9	3	26
Total	\$ 1,007	\$ 882	\$ 1,012	\$ 2,901

(1) Includes allowance for funds used during construction.

(2) Relates to construction of our Smarr Combined Cycle, Talbot Unit No. 7, and battery storage resource projects, net of approximately \$81 million in expected GRIP grant proceeds.

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

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

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 state and 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.

Depending on how we and the other co-owners of Plant 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 “OUR BUSINESS – REGULATION – Environmental.”

Credit Rating Risk

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

Our Ratings	S&P	Moody's	Fitch
Long-term ratings:			
Senior secured rating	BBB+	A3	BBB+
Issuer/unsecured rating ⁽¹⁾	BBB+	Baa1	BBB+
Rating outlook	Stable	Stable	Stable
Short-term rating:			
Commercial paper rating	A-2	P-2	F1

(1) We currently have no long-term debt that is unsecured; however, pricing of our \$1.275 billion syndicated line of credit is determined based on our unsecured or issuer ratings.

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, 2024, our maximum potential collateral requirements were as follows:

At senior secured rating levels:

- approximately \$50 million at a senior secured level of BBB-/Baa3,
- approximately \$142 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured or issuer rating levels:

- approximately \$56 million at a senior unsecured or issuer rating level of BB+/Ba1 or below.

Additionally, if certain of our pipeline, natural gas and power trading counterparties have reasonable grounds for insecurity regarding our ability to meet our obligations or we have experienced a material change in creditworthiness, including a significant credit ratings downgrade, these counterparties could require us to post an additional \$43 million in collateral, based on their credit exposure to us as of December 31, 2024.

Under certain of our new natural gas transportation precedent agreements, the potential collateral we could be required to post to our counterparties will increase by up to \$270 million after service begins under these agreements (currently projected for November 2028) upon a senior secured credit rating downgrade below investment grade by two rating agencies.

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 credit agreements and pollution control bond agreements contain provisions based on our ratings that, upon a credit rating downgrade below specified levels, could result in increased interest rates. Also, borrowing rates, letter of credit fees and commitment fees in two of our lines 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.

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 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

We are exposed to the risk of changes in interest rates relating to a portion of our debt. We categorize our debt as variable rate, which is debt that is subject to a change in interest rates within the next year, intermediate-term fixed rate debt, which is debt that is not subject to a change in interest rates within the next year, but is subject to a change in interest rates within the next five years, or long-term fixed rate debt, which is debt that is not subject to a change in interest rates within the next five years. At December 31, 2024, we had \$904.3 million of variable rate debt, no intermediate-term fixed rate debt, and the remainder of our debt was long-term fixed rate debt. Our \$904.3 million of variable rate debt at December 31, 2024, included \$400.1 million of commercial paper outstanding (which typically has maturities of between 1 and 90 days) and \$504.2 million of pollution control bonds. These pollution control bonds include \$191.4 million of indexed variable rate bonds, which are subject to repricing weekly, and \$312.8 million of five to seven-year term rate bonds that were subject to repricing in February 2025. In February 2025, we repriced \$272.2 million of the term rate bonds to new five-year term rate and converted \$40.5 million to a weekly rate mode.

At December 31, 2024, the weighted average interest rate on our variable rate debt was 3.8%. If, during 2024, 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 \$8.7 million.

Our objective in managing interest rate risk is to maintain a balance of long-term fixed, intermediate-term fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. At December 31, 2024, we had 7.1% of our total debt, including commercial paper, classified as variable rate and none of our debt classified as intermediate-term fixed rate. The remaining 92.9% of our debt was classified as long-term fixed rate.

The operative documents underlying the pollution control bond debt contain provisions that allow us to convert the debt that is not fixed to maturity 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 new long-term debt we expect to incur in connection with anticipated capital expenditures, such as for the issuance of long-term debt related to the Smarr Combined Cycle project, Talbot Unit No. 7 project and for recent acquisitions, as well as the short-term debt we plan to use for interim financing of our various projects.

Investment Risks

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. 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. For further discussion on our nuclear decommissioning trust funds, see Note 1 of Notes to Consolidated Financial Statements in Appendix A.

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.

Changes in interest rates also affect the market value of fixed income investments and rising interest rates may adversely affect the market value of fixed income investments in our nuclear and coal ash pond decommissioning funds. While we generally intend to hold these investments to maturity, sale of fixed income investments could lead to realizing losses on certain investments. While increases in interest rates may decrease the market value of fixed income assets, it may increase the amount of interest received for newly purchased fixed income investments and for funds invested in variable interest rate assets.

A 10% decline in the value of the internal and external funds’ equity and fixed income securities as of December 31, 2024 would result in a loss of value to the funds of approximately \$78.6 million.

We also maintain funds to finance our coal ash pond retirement obligations and for major maintenance expenses. We invest a portion of our coal ash decommissioning and major maintenance accounts in fixed income funds that are subject to changes in market value. A 10% decrease in the market value of these funds would be approximately \$22.8 million.

Commodity Price Risk

We are also exposed to the risk of changing prices for fuels, including coal and natural gas.

Coal

We have interests in 982 megawatts of coal-fired nameplate capacity at Plant Scherer. 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 stockpile are expected to provide fixed prices for 94% and 69% of our forecasted coal requirements for 2025 and 2026, 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 seven 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 seven years.

Natural Gas

We own or operate twelve gas fired generation facilities totaling over 5,700 megawatts of nameplate capacity. See “PROPERTIES – Generating Facilities” and “OUR 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, 19 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 and a half 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, 2024 was a net asset of approximately \$28.6 million, which represents the net amount we would have received if the swaps had been terminated as of that date. As of December 31, 2024, approximately 19% of our 2025 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 \$22.7 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 active participation in this program at any time.

Changes in Risk Exposure

Our exposure to changes in interest rates, the value of investments we hold, and commodity prices have not changed materially from the previous reporting period.

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 may only 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.

Our board of directors currently has one vacancy for an outside director position. Our members did not fill the vacancy at our 2025 annual member meeting.

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 the new candidate. Should that candidate also fail to receive a majority vote, this nomination and election process would be repeated until a nominated candidate is elected by a majority of the members.

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

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

Board of Directors Leadership Structure

Our principal executive officer and chairman of the board positions are separate and are held by different persons. The chairman of the board and any vice-chairman of the board are elected annually by a majority vote of the members of our board of directors. Our president and chief executive officer is appointed by our board of directors. None of our executive officers or 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:		
Annalisa M. Bloodworth	46	President and Chief Executive Officer
Elizabeth B. Higgins	56	Executive Vice President and Chief Financial Officer
Heather H. Teilhet	49	Executive Vice President, External Affairs
William F. Ussery	60	Executive Vice President, Member Relations
Richard D. Wallen	54	Executive Vice President and Chief Operating Officer
Jami G. Reusch	62	Senior Vice President, Human Resources
Suzanne N. Roberts	42	Senior Vice President and General Counsel
Directors:		
Marshall S. Millwood	75	Chairman and Member Group Director (Group 3)
James I. White	79	Vice-Chairman and Member Group Director (Group 1)
Jimmy G. Bailey	76	At-Large Director
Ronnie M. Hendricks	56	At-Large Director
Horace H. Weathersby III	65	At-Large Director
George L. Weaver	77	Member Group Director (Group 1)
Danny L. Nichols	60	Member Group Director (Group 2)
Sammy G. Simonton	83	Member Group Director (Group 2)
Christopher L. Stephens	56	Member Group Director (Group 3)
Fred A. McWhorter	78	Member Group Director (Group 4)
Jeffrey W. Murphy	61	Member Group Director (Group 4)
Ernest A. “Chip” Jakins III	54	Member Group Director (Group 5)
Kevin W. Bush	40	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 officers. Certain of our executive officers have 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

Annalisa M. Bloodworth is our President and Chief Executive Officer and has served in that capacity since February 1, 2025. Ms. Bloodworth joined Oglethorpe in 2010 and served in various roles prior to taking her current position, most recently as Senior Vice President and General Counsel. Prior to joining Oglethorpe, Ms. Bloodworth was in private practice at Eversheds Sutherland (US) LLP. In addition to energy, her experience includes significant work in commercial real estate development, dispute resolution, regulatory compliance, and construction. 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 the International Women’s Forum, Leadership Georgia, and Leadership Atlanta. She serves as Treasurer for the board of

directors of Murphy-Harpst Children's Home, and is a Past-President of the Emory University School of Law Alumni Board.

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. Ms. Higgins is a member of the Rotary Club of Atlanta, the International Women's Forum and Leadership Atlanta. She serves on the board of directors for Voices for Georgia's Children and represents Oglethorpe on the Metro Atlanta Chamber board of advisors. She also serves on the advisory board of FM Global, one of our property insurers, and the CFO Forum Atlanta. She has volunteered as a mentor with Pathbuilders, a development program for high potential women, since 2017.

Heather H. Teilhet is our Executive Vice President, External Affairs and has served in that capacity since February 2025. Prior to this position, Ms. Teilhet was our Senior Vice President, External Affairs since 2020. Ms. Teilhet joined us in January 2017 as Vice President of Governmental Affairs. Prior to joining Oglethorpe, 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's 81st Governor, Sonny Perdue. Ms. Teilhet graduated from the University of Georgia and holds a Masters in Public Administration from Georgia State University.

William F. Ussery is our Executive Vice President, Member 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 Executive Vice President, Member and External Relations. In January 2020, Mr. Ussery's title changed to Executive Vice President, Member Relations. 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.

Richard D. Wallen is our Executive Vice President and Chief Operating Officer, and began serving in that capacity on March 31, 2025. Mr. Wallen has more than 30 years of energy generation experience. From 2017 to February 2025, he was the Chief Executive Officer and General Manager of the Grant County Public Utility District in Washington and was responsible for providing power to more than 50,000 meters across Grant County. From 2014 to 2017, Mr. Wallen was with Oglethorpe as our Plant General Manager and Combustion Turbine Fleet Manager and was responsible for operating our combustion turbine facilities. Prior to that he worked for Siemens Energy Inc., Duke Energy, Dominion Energy and Carolina Power and Light. Before moving to the utility industry, Mr. Wallen served as a Chief Mechanical Operator with the U.S. Navy for eleven years and was a nuclear power plant operator aboard the USS Enterprise. He earned his bachelor's degree from West Virginia University and received a master's degree in business management from Clayton State University.

Jami G. Reusch is our Senior Vice President, Human Resources and has served in that office since July 2004. In February 2025, Ms. Reusch's title changed from Vice President, Human Resources, to Senior Vice President, Human Resources. 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 holds several Senior Professional certificates in Human Resources Management.

Suzanne N. Roberts is our Senior Vice President and General Counsel and has served in that capacity since February 1, 2025. Ms. Roberts joined Oglethorpe in 2016 and served in various roles prior to taking her current position, most recently as Deputy General Counsel. Prior to joining Oglethorpe, Ms. Roberts was in private practice at Alston & Bird LLP. In addition to energy, her legal experience includes commercial litigation, mergers and acquisitions, bankruptcy, real estate, regulatory compliance, and construction contracting. Ms. Roberts is a graduate of Duke University where she earned her Bachelor of Arts, double majoring in Economics and Public Policy. Ms. Roberts earned her Juris Doctor degree summa cum laude from Georgia State University College of Law. Ms. Roberts volunteers her time with Duke University's Sui Generis program.

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 2028. Mr. Bailey is a member of the compensation committee and the construction project committee. Mr. Bailey is a director of the Diverse Power Incorporated, an EMC, and served as the Chairman of Diverse Power board from 2018 to 2020. Mr. Bailey owned and operated a construction contracting business from 1970 to 2018. He also served as Chairman of Kudzu Networks Inc., a subsidiary of Diverse Power, and was President of the Georgia Directors Association in 2017 and 2018.

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 2026. Mr. Jakins is chairman of the compensation committee and also serves on the construction project 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 compensation committee, for Georgia Electric Membership Corporation where he is a member of the Economic Development Committee, and for Green Power EMC. He is also a member of the Georgia Chamber of Commerce.

Kevin W. Bush is an outside director. Mr. Bush was elected to our board of directors on March 31, 2025, and his present term will expire in March 2027. Mr. Bush is a member of our audit committee. Since 2019, Mr. Bush has served as Chief Financial Officer for the Shadday Family Office, which manages a portfolio of real estate and operating companies, including Big Dan's Car Wash. Prior to that, Mr. Bush was Chief Financial Officer of Superior Transport Inc., also owned by Shadday Family Office at that time, from 2011 until 2017 when he led the successful sale of the company. Mr. Bush began his career in public accounting with Whittington, Jones & Rudert where he specialized in assurance services. He is a licensed certified public accountant and a member of the American Institute of Certified Public Accountants and Georgia Society of CPAs. Mr. Bush holds a Bachelor of Science degree in accounting from North Georgia College and a Master of Business Administration in Business Administration from Berry College.

Ronnie M. Hendricks is an at-large director. Mr. Hendricks was elected to our board of directors on March 31, 2025, and his present term will expire in March 2028. Mr. Hendricks is a member of the audit committee. Mr. Hendricks is Chairman of the board of directors for Upson Electric Membership Corporation and has served on the Upson EMC board since 1999. Mr. Hendricks is currently the Assistant County Manager for Talbot County, Georgia

and has served in that capacity since 2017. Prior to that, he owned Ronnie Hendricks Electrical and was self-employed as an electrical contractor for 25 years. Mr. Hendricks is also on the board of directors for Georgia Electric Membership Corporation and he is the former Chairman of the Talbot County Tax Assessors Board and former Vice-Chairman of the Talbot County Planning Commission.

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 2028. He is a member of the compensation committee and the construction project committee. Mr. McWhorter serves as 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 Chairman of the Board and a member group director (group 3). Mr. Millwood has served on our board of directors since March 2003, and his present term will expire in March 2026. 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 2027. 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 2026. Mr. Nichols is the chairman of the construction project committee and also serves on the compensation committee. Mr. Nichols is the President/Chief Executive Officer 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 2027. He is a member of the audit 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.

Christopher L. Stephens is a member group director (group 3). Mr. Stephens was elected to our board of directors on March 31, 2025, and his present term will expire in March 2028. Mr. Stephens is a member of the compensation committee and the construction projects committee. Mr. Stephens is the President and Chief Executive Officer of Coweta-Fayette Electric Membership Corporation and has served in that capacity since 2014. Mr. Stephens first joined Coweta-Fayette EMC in 1996 as a Supervisor of Engineering and was promoted to various positions, including Senior Vice President of Engineering, before assuming his current role. Mr. Stephens also assumed the role of Chief Executive Officer of True Natural Gas on April 1, 2025. He is currently Chairman of the board of directors for GRESKO Utility Supply, Inc., Secretary-Treasurer for Georgia Electric Membership Corporation and on the board of directors for Piedmont Newnan Hospital and is the former Chairman of the Fayette County Chamber of Commerce and former President of the Georgia EMC Managers Association.

Horace H. Weathersby III is an at-large director. Mr. Weathersby has served on our board of directors since 2022, and his present term will expire in March 2026. He is a member of the compensation committee and the construction committee. Mr. Weathersby is a director of Planters Electric Membership Corporation where he has served since 2006 and currently serves as Chairman. Mr. Weathersby is the owner of Millen Peanut Company and Horace Weathersby Farms. Mr. Weathersby is also a director of Georgia Electric Membership Corporation, Jenkins County Commission and South Jenkins Volunteer Fire Department.

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 March 2028. 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 Meridian Cooperative and is a former director of Federated Rural Electric Insurance Corporation.

James I. White is Vice-Chairman of the Board and 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 2026. 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 owns a small farm in Henry County, Georgia and is the owner of T.K. White Real Estate Co. He was formerly the owner and president of Realty South Inc. Mr. White 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.” As of the date of this prospectus, the members of the audit committee are Jeffrey Murphy, Kevin Bush, Ronnie Hendricks, Sam Simonton, George Weaver and James White. Mr. Murphy is the chairman of the audit committee. The board of directors has determined that Mr. Bush 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. As of the date of this prospectus, the members of the compensation committee are Chip Jakins, Jimmy Bailey, Fred McWhorter, Danny Nichols, Christopher Stephens and Horace Weathersby. Mr. Jakins 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. As of the date of this prospectus, the members of the construction project committee are Danny Nichols, Jimmy Bailey, Chip Jakins, Fred McWhorter, Christopher Stephens and Horace Weathersby. 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.

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 and 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, 2024 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.

Certain of our executive officers have 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 officers 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 performance pay equal to 30% or 35% of his or her base salary, based on position, multiplied by the percentage of corporate goals achieved.

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 2024, 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 her 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 and 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 any employment agreements with our executive officers 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, if applicable, 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. She and our senior 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 levels remain competitive, we review standardized surveys to compare our total compensation program against other companies in the utility industry of a similar size. 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 executive compensation levels at other companies do not drive our compensation decisions. For our employees overall and for our executive officers, we review market compensation levels as a reference point in our overall compensation review process.

In order to supplement our internal review of generally available market data, we periodically hire a compensation consultant to provide us with supplemental market information to help us evaluate our compensation practices. In 2024, we engaged an independent consultant to provide supplemental market data regarding the relative competitiveness of our 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 2024, 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.

For an executive officer to earn his or her maximum performance pay, 100% of the performance measures must be achieved. The performance measures are weighted to align with our current strategic focus. Goals are reviewed annually and may be adjusted in order to reflect any changes in our strategic focus. 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 work time. Our safety performance goals are focused on serious injuries and fatalities, safety training and meetings, enhancing our safety program and procedures and reducing workplace hazards for both our employees and contractors.

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 or the operator of certain co-owned facilities must operate and maintain these facilities in a manner that minimizes long-term outage and replacement energy costs. 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 management and involvement regarding construction at our owned and co-owned generating facilities. Our most significant project for 2024 was the completion of Vogtle Unit 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. Other components measure construction progress at Vogtle Unit No. 4 project as well as several construction projects that we directly oversee. We measure performance based on successful project completion in a timely manner and within project budget. Following the completion of Vogtle Unit No. 3 in 2023, we reduced the weighting of the Vogtle project for this goal and added and increased the weighting of several construction projects at our other plants.

Corporate Compliance. Our corporate compliance goals are divided into two categories – environmental and electric reliability standards. These environmental goals promote our commitment to responsible environmental stewardship while providing reliable and affordable energy. We measure our performance by the number and severity 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 related to protection of our critical and non-critical infrastructure.

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 the 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 on a long-term basis. Any cost savings included in this goal must be over and above what would generally be expected. For 2024, we may earn up to an additional 5% of performance pay by identifying cost savings or reduction strategies above the initial \$50 million goal. Two other financial goals focus on our internal controls 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 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 2024, we multiplied 30% or 35%, based on position, of each executive officers' base salary by the corporate goal achievement percentage to determine his or her performance bonus.

Assessment of Performance of 2024 Corporate Goals

The specific corporate performance measures, thresholds, maximums and results for our executive officers' 2024 performance pay were the following:

Performance Category/ Description	Performance Measure	Threshold	Maximum	2024 Result	Weight	Weighted Goal Achieved
Safety						
Incident Rate	Serious Injuries and Fatalities	0	0	100.0 %	3.0 %	3.00 %
Safety Program ⁽¹⁾	Safety Training and Meetings	100.0 %	100.0 %	100.0 %	1.0 %	1.00 %
	Safety Observation Program	216/120	360/240	100.0 %	2.5 %	2.50 %
	Hazard Reduction Program	75.0 %	100.0 %	100.0 %	0.5 %	0.50 %
Operations⁽²⁾						
Oglethorpe Managed	Successful Starts	97.2 %	100.0 %	100.0 %	4.0 %	3.76 %
	Peak Season Availability	55.6 %	99.9 %	83.4 %	23.0 %	19.17 %
Co-Owned Fleet	Coal Fleet Peak Season Equivalent Forced Outage Rate	6.0 %	3.0 %	1.4 %	0.65 %	0.65 %
	Coal Fleet Annual Equivalent Unplanned Unavailability Factor	5.8 %	3.3 %	3.2 %	0.35 %	0.28 %
	Nuclear Fleet Capability Factor	90.7 %	92.7 %	93.7 %	3.0 %	2.21 %
Construction and Project Management						
Vogtle Units No. 3 and No. 4	Oglethorpe Performance	0.0 %	100.0 %	100.0 %	3.5 %	3.50 %
	Project Milestones	Meet applicable deadlines		100.0 %	1.5 %	1.50 %
Oglethorpe Managed Projects	Status of Projects	Meet applicable deadlines & budgets		88.8 %	10.0 %	8.87 %
Corporate Compliance						
Environmental	Final Notices of Violation and Letters of Non-Compliance	1 (if fine is ≤ \$5,000) or 2	0	0	4.0 %	4.00 %
	Reportable Spills	1	0	0	4.0 %	4.00 %
Mandatory Electric Reliability Standards	Non-Critical Infrastructure Protection Compliance	1+ (if minimal penalty)	0	0	3.0 %	3.00 %
	Critical Infrastructure Protection Compliance	1+ (if minimal penalty)	0	0	3.0 %	3.00 %
Financial						
Cost Saving	Current Year / Long-Term Savings	\$ 0	\$ 50,000,000	\$ 55,370,353	14.0 %	14.00 %
	Additional Cost Savings	\$ 0	\$ 50,000,000	\$ 50,000,000	0-5.0%	5.00 %
Internal Control over Financial Reporting	Significant Deficiency Or Material Weakness	0	0	0	2.0 %	2.00 %
	Control Deficiency	0	0	0	2.0 %	2.00 %
Quality						
Board Satisfaction	Board of Directors Survey	80.0 %	100.0 %	94.6 %	15.0 %	14.19 %
Total					100.0 %	98.13 %

(1) Certain sub-goals are 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 based on all of the generating units within the category.

As noted above, we achieved 98.13% of our corporate goals for 2024. As a result, Mr. Smith, Ms. Higgins and Mr. Sorrick received performance pay in an amount equal to 98.13% of 35% of his or her base salary and Mr. Ussery and Ms. Bloodworth received performance pay in an amount equal to 98.13% of 30% 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 2024:

Executive Officer	Performance Pay*
Michael L. Smith ⁽¹⁾	\$ 372,198
Elizabeth B. Higgins	213,286
David W. Sorrick ⁽²⁾	199,204
William F. Ussery	138,540
Annalisa M. Bloodworth	142,190

* Performance pay was calculated based on base salaries as of December 31, 2024. Actual compensation earned in 2024 is reported in the Summary Compensation Table below.

- (1) Mr. Smith retired from Oglethorpe on January 31, 2025.
- (2) Mr. Sorrick resigned from Oglethorpe on January 7, 2025.

Employment Agreements

General

We have an employment agreement with Ms. Bloodworth, Ms. Higgins and Mr. Ussery. 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 these 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.

Our employment agreement with Ms. Bloodworth extends through December 31, 2027. Ms. Bloodworth'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. Ms. Bloodworth's minimum annual base salary under her agreement is \$906,000, and is subject to review and adjustment by our board of directors. Ms. Bloodworth is eligible to participate in incentive compensation plans generally available to similarly situated employees and for an annual bonus determined by our board of directors at its sole discretion. Ms. Bloodworth is also entitled to an automobile or an automobile allowance during the term of the agreement. Ms. Bloodworth's employment agreement contains severance pay provisions.

We also have employment agreements with Ms. Higgins and Mr. Ussery. The current term of Ms. Higgins' and Mr. Ussery's agreements extends through December 31, 2027 and will automatically renew 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 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 \$671,000 for Ms. Higgins and \$470,600 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 to participate in incentive compensation plans generally available to similarly situated employees and for an annual bonus determined by the president and chief executive officer at his sole discretion. The employment agreements with Ms. Higgins and Mr. Ussery contain severance pay provisions.

We have also entered into a retention agreement with Ms. Higgins. Pursuant to the terms of this agreement, Ms. Higgins will receive a bonus of \$200,000, \$300,000, \$350,000 and \$350,000 provided she is our Executive Vice President and Chief Financial Officer as of December 31, 2025, 2026, 2027 and 2028, respectively.

Assessment of Severance Arrangements

Pursuant to their respective employment agreements, certain of our executive officers are entitled to 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 Ms. Bloodworth's role and responsibility within Oglethorpe in relation to the total amount of severance pay she would receive upon the occurrence of a severance event. The committee also considered whether the amount Ms. Bloodworth would receive upon severance was appropriate given her 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 Ms. Bloodworth. 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 Ms. Bloodworth faces in her 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 her employment agreement, Ms. Bloodworth will be entitled to a lump-sum severance payment upon the occurrence of any of the following events: (1) we terminate her employment without cause; or (2) she resigns due to a demotion or material reduction of her position or responsibilities, a material reduction of her base salary, or a relocation of her principal office by more than 50 miles. The severance payment will equal Ms. Bloodworth'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 an amount equal to her costs for medical and dental continuation coverage under COBRA, each for the longer of one year or the remaining term of the agreement, and is payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. In addition, Ms. Bloodworth will be entitled to one year outplacement services. Severance is payable only if Ms. Bloodworth signs a form releasing all claims against us. The maximum severance that would be payable to Ms. Bloodworth in the circumstances described above is \$1,866,703.

Our president and chief executive officer considered the total amount of compensation Ms. Higgins and Mr. Ussery would receive upon the occurrence of a severance event and determined that it was appropriate for these executive officers to receive severance compensation equal to a maximum of two years of his or her then current base salary, plus benefits as described below, because such agreements provide a measure of stability for both us and the executive officers. In addition, like our president and chief executive officer, these executive officers are not compensated using options or other forms of equity compensation that lead to significant wealth accumulation. Therefore, our president and chief executive officer 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, 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 the executive officer'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 an amount equal to the executive's cost for medical and dental continuation coverage under COBRA for one year payable within 30 days of termination, subject to the provisions of Internal Revenue Code Section 409A. In addition, the executive will be entitled to one year of outplacement services paid directly to the outplacement firm. Severance is payable only if the executive signs a form releasing all claims against us. The maximum severance that would be payable to Ms. Higgins and Mr. Ussery in the circumstances described above is \$1,448,895 and \$1,013,895, respectively.

Compensation Committee Interlocks and Insider Participation

Mr. Jakins, Mr. Bailey, Mr. McWhorter, Mr. Millwood, Mr. Nichols and Mr. Weathersby served as members of our compensation committee during all or a portion of 2024 and continue to serve on the committee in 2025. Mr. Stephens joined the compensation committee on March 31, 2025.

Mr. 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 \$393.1 million to us in 2024 under its wholesale power contract accounted for approximately 18.0% of our total revenues.

Mr. Nichols is a director of ours and is the President and Chief Executive Officer of Colquitt Electric Membership Corporation. Colquitt is a member of ours and has a wholesale power contract with us. Colquitt's revenues of \$47.3 million to us in 2024 under its wholesale power contract accounted for approximately 2.2% of our total revenues.

Mr. Stephens is a director of ours and the President and Chief Executive Officer of Coweta-Fayette Electric Membership Corporation. Coweta-Fayette is a member of ours and has a wholesale power contract with us. Coweta-Fayette's revenues of \$103.0 million to us in 2024 under its wholesale power contract accounted for approximately 4.7% 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, 2024, 2023 and 2022.

Name and Principal Position	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	All Other Compensation ⁽¹⁾	Total
Michael L. Smith ⁽²⁾	2024	\$ 1,072,663	\$ —	\$ 372,198	\$ 233,401	\$ 1,678,262
Past President and	2023	1,007,450	—	342,394	196,817	1,546,661
Chief Executive Officer	2022	947,475	—	178,379	186,873	1,312,727
Elizabeth B. Higgins	2024	614,667	—	213,286	133,479	961,432
Executive Vice President and	2023	578,333	—	196,174	118,561	893,068
Chief Financial Officer	2022	549,167	—	103,452	113,797	766,416
David W. Sorrick ⁽³⁾	2024	574,333	—	199,204	126,800	900,337
Former Executive Vice President	2023	541,667	—	183,724	110,200	835,591
and Chief Operating Officer	2022	484,168	—	88,851	110,233	683,252
William F. Ussery	2024	466,016	—	138,540	112,740	717,296
Executive Vice President,	2023	439,583	—	127,799	93,720	661,102
Member Relations	2022	417,833	—	78,661	97,440	593,934
Annalisa M. Bloodworth ⁽⁴⁾	2024	478,000	—	142,190	126,503	746,693
President and	2023	438,333	—	130,654	107,364	676,351
Chief Executive Officer	2022	390,750	—	75,492	95,858	562,100

(1) Figures for 2024 consist of matching contributions and contributions we made under the 401(k) Retirement Savings Plan on behalf of each Mr. Smith, Ms. Higgins, Mr. Sorrick, Mr. Ussery, and Ms. Bloodworth of \$46,000; contributions by Oglethorpe to a nonqualified deferred compensation plan on behalf of Mr. Smith, Ms. Higgins, Mr. Ussery, Ms. Bloodworth and Mr. Sorrick, respectively of \$165,169, \$71,443, \$46,056, \$48,353 and \$69,308; car allowances; paid time off, executive health benefits; customary holiday gifts and service awards.

(2) Mr. Smith retired from Oglethorpe on January 31, 2025.

(3) Mr. Sorrick resigned from Oglethorpe on January 7, 2025.

(4) Ms. Bloodworth was our Senior Vice President and General Counsel for the year ended December 31, 2024 and assumed the role of President and Chief Executive Officer on February 1, 2025.

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, 2024.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards	
		Threshold	Maximum
Michael L. Smith	N/A	\$ 105,626	\$ 379,290
Elizabeth B. Higgins	N/A	\$ 60,528	\$ 217,350
David W. Sorrick	N/A	\$ 56,532	\$ 203,000
William F. Ussery	N/A	\$ 40,352	\$ 144,900
Annalisa M. Bloodworth	N/A	\$ 39,316	\$ 141,180

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 2024 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 (\$345,000 as indexed).

The following table sets forth contributions for the fiscal year ended December 31, 2024 along with aggregate earnings for the same period.

Name	Executive Contributions in Last FY	Registrant Contributions in Last FY ⁽¹⁾	Aggregate Earnings (Loss) in Last FY ⁽²⁾	Aggregate Withdrawals/ Distributions in Last FY	Aggregate Balance at Last FYE
Michael L. Smith	\$ 52,680	\$ 165,169	\$ 198,979	\$ —	\$ 2,045,878
Elizabeth B. Higgins	\$ 8,400	\$ 71,443	\$ 193,122	\$ —	\$ 1,345,747
David W. Sorrick	\$ 14,136	\$ 69,308	\$ 12,961	\$ —	\$ 139,966
William F. Ussery	\$ 4,800	\$ 46,056	\$ 58,953	\$ —	\$ 564,803
Annalisa M. Bloodworth	\$ 12,768	\$ 48,353	\$ 36,387	\$ —	\$ 311,397

(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.

Pay Ratio Disclosure

We strive to provide fair and equitable compensation to each of our employees through a combination of competitive base pay, performance incentives, retirement plans and other benefits. The following pay ratio and supporting information compares the annual total compensation of Mr. Smith, our president and chief executive officer during 2024, to the annual total compensation of our median employee for the fiscal year ended December 31, 2024.

To identify our median employee, we determined that as of December 31, 2024, we had 379 employees, including full-time, part-time, temporary and seasonal workers (excluding our president and chief executive officer), who were all located in the United States. We then calculated the annual total compensation for each of these employees for the fiscal year ended December 31, 2024 in the same manner in which we calculated our president and chief executive officer’s total annual compensation presented in the “Summary Compensation Table.” Employee compensation includes salary, performance pay and benefits.

Based upon this analysis, we determined that our median employee’s annual total compensation for 2024 was \$167,958. As set forth in the Summary Compensation Table, our president and chief executive officer’s annual total compensation for 2024 was \$1,678,262. The ratio of our president and chief executive officer’s annual total compensation to our median employee’s annual total compensation for the fiscal year ended December 31, 2024 was 9.99:1.

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, 2024.

Name	Total Fees Earned or Paid in Cash
Member Directors	
Jimmy G. Bailey	\$ 59,695
Randy Crenshaw ⁽¹⁾	\$ 56,400
Ernest A. “Chip” Jakins III	\$ 57,975
Fred A. McWhorter	\$ 58,915
Marshall S. Millwood, Chairman	\$ 76,525
Jeffrey W. Murphy	\$ 56,400
Danny L. Nichols	\$ 53,475
Sammy G. Simonton	\$ 59,345
Horace H. Weathersby III	\$ 58,740
George L. Weaver	\$ 61,200
James I. White, Vice-Chairman	\$ 64,920
Outside Director	
Wm. Ronald Duffey ⁽²⁾	\$ 110,820

(1) Mr. Crenshaw’s term ended March 31, 2025.

(2) Mr. Duffey retired from our board of directors on March 31, 2025.

In 2024, we paid our member directors a per diem of \$3,100 for attending board meetings and \$1,400 for attending committee meetings or other official business approved by the chairman of the board of directors. Member directors were paid \$780 per day for attending our members’ annual meeting and for member advisory board meetings. We paid our outside director a per diem of \$7,000 for attending board meetings, \$1,400 for attending committee meetings or other official business approved by the chairman of the board of directors and \$1,000 to attend our members’ annual meeting. In addition, we reimburse all directors for reasonable out-of-pocket expenses incurred in attending a meeting. All directors were paid \$175 per hour when participating in meetings virtually. The per diem rate paid to the chairman of the board of directors will be increased by 20% for each per diem that includes a board of directors meeting as compensation for time involved in preparing for the meetings. The audit committee financial expert will be paid an additional per diem of \$680 for each per diem with an audit committee meeting as compensation for the time involved in fulfilling that role. Neither our outside director nor member directors receive any perquisites or other personal benefits from us.

Directors may choose up to three external training courses related to their role as director and/or the energy industry per year to attend. Our directors will be paid \$600 per day for each day of an external training course plus, where applicable, up to two additional days for time spent traveling to and from an external training course. Directors will be reimbursed for travel and out-of-pocket expenses for attending external training.

**SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND
RELATED STOCKHOLDER MATTERS**

Not applicable.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

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 \$393.1 million to us in 2024 under its wholesale power contract accounted for approximately 18.0% 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 \$31.5 million to us in 2024 under its wholesale power contract accounted for approximately 1.4% of our total revenues.

Danny Nichols is a director of ours and is the President and Chief Executive Officer of Colquitt Electric Membership Corporation. Colquitt is a member of ours and has a wholesale power contract with us. Colquitt's revenues of \$47.3 million to us in 2024 under its wholesale power contract accounted for approximately 2.2% of our total revenues.

Christopher Stephens is a director of ours and the President and Chief Executive Officer of Coweta-Fayette Electric Membership Corporation. Coweta-Fayette is a member of ours and has a wholesale power contract with us. Coweta-Fayette's revenues of \$103.0 million to us in 2024 under its wholesale power contract accounted for approximately 4.7% of our total revenues.

George Weaver is a director of ours and the President and Chief Executive Officer 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 \$92.8 million to us in 2024 under its wholesale power contract accounted for approximately 4.3% of our total revenues.

We have a Standards of Conduct/Conflict of Interest policy that sets forth guidelines that our employees and directors must follow in order to avoid conflicts of interest, or any appearance of conflicts of interest, between an individual's personal interests and our interests. Pursuant to this policy, each employee and director must disclose any conflicts of interest, actions or relationships that might give rise to a conflict. Our president and chief executive officer is responsible for taking reasonable steps to ensure that the employees are complying with this policy and the audit committee is responsible for taking reasonable steps to ensure that the directors are complying with this policy. The audit committee is charged with monitoring compliance with this policy and making recommendations to the board of directors regarding this policy. Certain actions or relationships that might give rise to a conflict of interest are reviewed and approved by our board of directors.

Director Independence

Because we are an electric cooperative, our 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 Electric Membership Corporation, an organization from which we received more than 5% of our gross revenues for the fiscal year ended December 31, 2024. 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.

THE EXCHANGE OFFERS

General; Purpose of the Exchange Offers

In connection with the issuance of the 2024A Original Bonds on June 21, 2024, we entered into a registration rights agreement with RBC Capital Markets, LLC, as representative of the initial purchasers of those bonds. In connection with the issuance of the 2025A Original Bonds on January 27, 2025, we entered into a registration rights agreement with J.P. Morgan Securities LLC, as representative of the initial purchasers of those bonds. Each registration rights agreement provides for a registered exchange offer. The exchange offers will permit eligible holders of Original Bonds to exchange their Original Bonds for Exchange Bonds, which are identical in all material respects to the Original Bonds, except that:

- i. the Exchange Bonds have been registered with the SEC under U.S. federal securities laws and will not bear any legend restricting their transfer;
- ii. the Exchange Bonds generally will not be subject to transfer restrictions and will not be entitled to registration rights;
- iii. the holders of the Exchange Bonds will not be entitled to earn additional interest under circumstances related to our registration obligations under the registration rights agreements; and
- iv. the Exchange Bonds will bear a different CUSIP number than the Original Bonds.

Pursuant to the registration rights agreements, we agreed, for the benefit of the holders of the Original Bonds, at our cost, to file an exchange offer registration statement relating to an offer to exchange the Original Bonds for Exchange Bonds and to:

- i. file the exchange offer registration statement with the SEC no later than 300 days after the issue date of the 2024A Original Bonds and 180 days after the issue date of the 2025A Original Bonds;
- ii. use commercially reasonable efforts to cause the exchange offer registration statement to become effective under the Securities Act within 390 days after the issue date of the 2024A Original Bonds and 270 days after the issue date of the 2025A Original Bonds; and
- iii. complete the exchange offer no later than 60 business days after commencing that exchange offer.

If we do not meet the timing obligations in the preceding sentence, or if we fail to meet certain other conditions described in the registration rights agreements, each, a “registration default,” the interest rate borne by the affected series of Original Bonds will increase at a rate of 0.25% per annum for the first 90-day period immediately following the occurrence of the registration default and at a rate of 0.50% per annum for the remaining portion of the registration default. Immediately upon the cure of all registration defaults, the accrual of the additional interest will cease and the interest rate on the affected series of Original Bonds will revert to the original rate.

Under some circumstances set forth in the registration rights agreements, holders of the Original Bonds, including holders who are not permitted to participate in the exchange offers, may require us to file, and cause to become effective, a shelf registration statement covering resales of the Original Bonds by these holders.

We are making the exchange offers in reliance on the position of the SEC as described in previous no-action letters issued to third parties, including in *Exxon Capital Holdings Corporation* (April 13, 1988), *Morgan Stanley & Co., Inc.* (June 5, 1991), *Shearman & Sterling* (July 2, 1993) and similar no-action letters. However, we have not sought our own no-action letter. Based upon these interpretations by the SEC, we believe that a holder who exchanges Original Bonds for Exchange Bonds in the exchange offers generally may offer the Exchange Bonds for resale, sell the Exchange Bonds and otherwise transfer the Exchange Bonds without further registration under the Securities Act and without delivery of a prospectus that satisfies the requirements of Section 10 of the Securities Act. The preceding sentence does not apply, however, to a holder who is our “affiliate” within the meaning of Rule 405 of the Securities Act. We also believe that a holder may offer, sell or transfer the Exchange Bonds only if the holder acknowledges that the holder is acquiring the Exchange Bonds in the ordinary course of its business and is

not participating, does not intend to participate and has no arrangement or understanding with any person to participate in a “distribution”, as defined in the Securities Act, of the Exchange Bonds. We have not entered into any arrangement or understanding with any person who will receive Exchange Bonds in the exchange offers to distribute such Exchange Bonds following completion of the exchange offers, and, to the best of our information and belief, we are not aware of any person that will participate in the exchange offers with a view to distribute the Exchange Bonds. A holder who exchanges Original Bonds for Exchange Bonds in the exchange offers for the purpose of distributing such Exchange Bonds cannot rely on the interpretations of the staff of the SEC in the aforementioned no-action letters, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any secondary resale of the Exchange Bonds and must be identified as an underwriter in the prospectus.

Each broker-dealer that receives the Exchange Bonds for its own account in exchange for the Original Bonds, where the Original Bonds were acquired by it as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the Exchange Bonds and that it has not entered into any agreement or understanding with us or any of our “affiliates”, as defined in Rule 405 under the Securities Act, to participate in a “distribution”, as defined under the Securities Act, of the Exchange Bonds. By so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. See “PLAN OF DISTRIBUTION.”

This summary of certain provisions of the registration rights agreements does not purport to be complete, and is qualified in its entirety by reference to, all the provisions of the registration rights agreements, which are incorporated by reference as exhibits to the registration statement of which this prospectus forms a part.

NEITHER WE NOR THE EXCHANGE AGENT MAKE ANY RECOMMENDATION TO YOU AS TO WHETHER YOU SHOULD TENDER OR REFRAIN FROM TENDERING ALL OR ANY PORTION OF YOUR ORIGINAL BONDS IN THE EXCHANGE OFFERS. IN ADDITION, NO ONE HAS BEEN AUTHORIZED TO MAKE THIS RECOMMENDATION. YOU MUST MAKE YOUR OWN DECISION WHETHER TO TENDER INTO THE EXCHANGE OFFERS AND, IF SO, THE AGGREGATE AMOUNT OF ORIGINAL BONDS TO TENDER AFTER READING THIS PROSPECTUS AND THE ACCOMPANYING LETTER OF TRANSMITTAL AND CONSULTING WITH YOUR ADVISORS, IF ANY, BASED ON YOUR FINANCIAL POSITION AND REQUIREMENTS.

Terms of the Exchange Offers

We are offering holders of the Original Bonds the opportunity to exchange their Original Bonds for Exchange Bonds subject to the terms and conditions set forth in this prospectus and in the accompanying letter of transmittal. Subject to the terms and the satisfaction or waiver of the conditions detailed in this prospectus, we will accept for exchange all Original Bonds properly tendered on or prior to 5:00 p.m., New York City time, on _____, 2025, which we refer to as the expiration date, and not validly withdrawn as permitted below. However, we may extend, in our sole discretion, the period during which either of the exchange offers is open. If extended, the term expiration date shall mean the latest time and date to which the relevant exchange offer is extended.

The terms of the Exchange Bonds will be substantially identical to the terms of the Original Bonds, except the Exchange Bonds will be registered under the Securities Act, will not bear legends restricting their transfer and will not contain terms with respect to additional interest upon our failure to fulfill our obligations under the registration rights agreements. Each series of Exchange Bonds will evidence the same debt as the Original Bonds. The Exchange Bonds will be issued under and secured by the same indenture under which the Original Bonds were issued. For a description of the indenture, see “SUMMARY OF THE FIRST MORTGAGE INDENTURE.”

As of the date of this prospectus, \$350,000,000 aggregate principal amount of the 5.800% Green First Mortgage Bonds, Series 2024A due 2054 are outstanding and \$350,000,000 aggregate principal amount of the 5.900% Green First Mortgage Bonds, Series 2025A due 2055 are outstanding. This prospectus and the accompanying letter of transmittal are being sent to all registered holders of the Original Bonds. There will be no fixed record date for determining registered holders of Original Bonds entitled to participate in the exchange offers. We intend to conduct

the exchange offers in accordance with the provisions of the registration rights agreements, the applicable requirements of the Securities Act and the Exchange Act and the rules and regulations of the SEC.

The exchange offers are not conditioned upon any minimum aggregate principal amount of Original Bonds being tendered for exchange. Any Original Bonds not tendered will remain outstanding and continue to accrue interest and will be entitled to the rights and benefits such holders have under the first mortgage indenture except we will not have any further obligation under the related registration rights agreement, except as otherwise specified therein.

Original Bonds may only be tendered in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof. We will issue Exchange Bonds in principal amounts identical to Original Bonds surrendered in the exchange offers.

We expressly reserve the right, at any time prior to the expiration of either exchange offer, to extend the period during which that exchange offer is open and delay acceptance for exchange of any Exchange Bonds, by giving oral or written notice of such extension to holders thereof as described below. Any extension notice will disclose the approximate number of Original Bonds tendered by holders as of the date of the extension notice. During any such extension, all the Original Bonds previously tendered will remain subject to the relevant exchange offer and may be accepted for exchange by us. Any Original Bonds not accepted for exchange for any reason will be returned without expense to an account maintained with DTC promptly upon expiration or termination of the corresponding exchange offer.

Subject to the terms of the registration rights agreements, we expressly reserve the right to amend or terminate the exchange offers, and not to accept for exchange any Original Bonds, upon the occurrence of any of the conditions of the exchange offers specified under “—Conditions to the Exchange Offers.” We will give oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the Original Bonds as promptly as practicable. Such notice, in the case of any extension, will be issued by means of a press release or other public announcement no later than 9:00 AM, New York City time, on the next business day after the previously scheduled expiration date.

Procedures for Tendering Original Bonds

Your tender to us of Original Bonds as set forth below and our acceptance of the Original Bonds will constitute a binding agreement between us and you upon the terms and subject to the conditions set forth in this prospectus and the accompanying letter of transmittal. Except as set forth below, to tender Original Bonds for exchange pursuant to the exchange offers, you must transmit a properly completed and duly executed letter of transmittal, including all other documents required by the letter of transmittal or, in the case of a book-entry transfer, an agent’s message in lieu of the letter of transmittal, to U.S. Bank Trust Company, National Association, as exchange agent, at the address set forth below under “—Exchange Agent” on or prior to the expiration date. In addition, either:

- a timely confirmation of a book-entry transfer of such Original Bonds into the exchange agent’s account at DTC pursuant to the procedure for book-entry transfer must be received by the exchange agent, prior to the expiration date, with the letter of transmittal or an agent’s message in lieu of such letter of transmittal; or
- certificates for such Original Bonds must be received by the exchange agent along with the letter of transmittal; or
- you must comply with the guaranteed delivery procedures described below.

The term “agent’s message” means a message, transmitted by DTC to and received by the exchange agent and forming a part of a book-entry transfer, which states that DTC has received an express acknowledgment from the tendering participant stating that such participant has received and agrees to be bound by the letter of transmittal, or, in the case of an agent’s message relating to guaranteed delivery, that such participant has received and agrees to be bound by the notice of guaranteed delivery.

The method of delivery of Original Bonds, letters of transmittal and all other required documents is at your election and risk. Delivery of such documents will be deemed made only when actually received by the exchange agent. If such delivery is by mail, it is recommended that you use registered mail, properly insured, with return receipt requested. In all cases, you should allow sufficient time to assure timely delivery. No letter of transmittal or Original Bonds should be sent to us.

Signatures on a letter of transmittal or a notice of withdrawal, as the case may be, must be guaranteed unless the Original Bonds surrendered for exchange are tendered:

- by a holder of the Original Bonds who has not completed the box entitled “Special Issuance Instructions” or “Special Delivery Instructions” on the letter of transmittal; or
- for the account of an eligible institution (as defined below).

In the event that signatures on a letter of transmittal or a notice of withdrawal are required to be guaranteed, such guarantees must be by a firm which is a member of the Securities Transfer Agent Medallion Program, the Stock Exchanges Medallion Program or the New York Stock Exchange Medallion Program (each such entity being hereinafter referred to as an “eligible institution”). If Original Bonds are registered in the name of a person other than the signer of the letter of transmittal, the Original Bonds surrendered for exchange must be endorsed by, or be accompanied by a written instrument or instruments of transfer or exchange, in satisfactory form as we or the exchange agent determine in our discretion, duly executed by the registered holders with the signature thereon guaranteed by an eligible institution.

If the letter of transmittal is signed by a person or persons other than the registered holder or holders of Original Bonds, such Original Bonds must be endorsed or accompanied by powers of attorney signed exactly as the name(s) of the registered holder(s) that appear on the Original Bonds.

If the letter of transmittal or any Original Bonds or powers of attorney are signed by trustees, executors, administrators, guardians, attorneys-in-fact, officers of corporations or others acting in a fiduciary or representative capacity, such persons should so indicate when signing. Unless waived by us or the exchange agent, proper evidence satisfactory to us of their authority to so act must be submitted with the letter of transmittal.

If you are a beneficial owner whose Original Bonds are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and wish to tender your Original Bonds, you should promptly instruct the registered holder to tender such Original Bonds on your behalf. Any registered holder that is a participant in DTC’s book-entry transfer facility system may make book-entry delivery of the Original Bonds by causing DTC to transfer the Original Bonds into the exchange agent’s account.

If you wish to tender your Original Bonds in the exchange offers on your own behalf, prior to completing and executing the letter of transmittal and delivering your Original Bonds, you must either make appropriate arrangements to register ownership of the Original Bonds in your name with DTC or obtain a properly completed bond power from the person in whose name the Original Bonds are registered.

We or the exchange agent, in our discretion, will make a final and binding determination on all questions as to the validity, form, eligibility (including time of receipt) and acceptance of the Original Bonds tendered for exchange. We reserve the right to reject any and all tenders not validly tendered or to not accept any tender which acceptance might, in our judgment or our counsel’s, be unlawful. We also reserve the right to waive any defects or irregularities or conditions of the exchange offers as to any individual tender before the expiration date (including the right to waive the ineligibility of any holder who seeks to tender the Original Bonds in the exchange offer). Our or the exchange agent’s interpretation of the terms and conditions of the exchange offers (including the letter of transmittal and the instructions thereto) as to any particular tender either before or after the expiration date will be final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of the Original Bonds for exchange must be cured within a reasonable period of time, as we determine. We are not nor is the exchange agent or any other person under any duty to notify you of any defect or irregularity with respect to your tender of the Original Bonds for exchange, and no one will be liable for failing to provide such notification.

By tendering the Original Bonds, you represent to us that:

- i. any Exchange Bonds you receive will be acquired in the ordinary course of your business;
- ii. you are not participating and have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Bonds;
- iii. you are not our “affiliate” (within the meaning of Rule 405 under the Securities Act); and
- iv. if you are a broker-dealer that will receive Exchange Bonds for your own account in exchange for Original Bonds that were acquired as a result of market-making or other trading activities, then you will deliver a prospectus (or, to the extent permitted by law, make available a prospectus to purchasers) in connection with any resale of such Exchange Bonds.

For further information regarding resales of the Exchange Bonds by participating broker-dealers, see “PLAN OF DISTRIBUTION.”

If any holder or other person is an “affiliate” of ours (within the meaning of Rule 405 under the Securities Act), or is participating or has an arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of the Exchange Bonds, that holder or other person cannot rely on the applicable interpretations of the staff of the SEC, may not tender its Original Bonds in the exchange offers and must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

Each broker-dealer that receives the Exchange Bonds for its own account in exchange for the Original Bonds, where the Original Bonds were acquired by it as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus that meets the requirements of the Securities Act in connection with any resale of the Exchange Bonds. By so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act (other than in connection with a resale of an unsold allotment from the original sale of the Original Bonds).

Furthermore, any broker-dealer that acquired any of its Original Bonds directly from us:

- may not rely on the applicable interpretation of the SEC staff’s position contained in its *Exxon Capital Holdings Corp.* (April 13, 1988), *Morgan, Stanley & Co. Inc.* (June 5, 1991) and *Shearman & Sterling* (July 2, 1993) no-action letters; and
- must also be named as a selling noteholder in connection with the registration and prospectus delivery requirements of the Securities Act relating to any resale transaction.

By delivering a letter of transmittal or an agent’s message, a holder or a beneficial owner (whose Original Bonds are registered in the name of a broker, dealer, commercial bank, trust company or other nominee) will have or will be deemed to have irrevocably appointed the exchange agent as its agent and attorney-in-fact (with full knowledge that the exchange agent is also acting as an agent for us in connection with the exchange offer) with respect to the Original Bonds, with full power of substitution (such power of attorney being deemed to be an irrevocable power coupled with an interest subject only to the right of withdrawal described in this prospectus), to receive for our account all benefits and otherwise exercise all rights of beneficial ownership of such Original Bonds, in accordance with the terms and conditions of the exchange offers.

Each holder or beneficial owner will also have or be deemed to have represented and warranted to us that it has authority to tender, exchange, sell, assign and transfer the Original Bonds it tenders and that, when the same are accepted for exchange, we will acquire good, marketable and unencumbered title to such Original Bonds, free and clear of all liens, restrictions, charges and encumbrances, and that the Original Bonds tendered are not subject to any proxies or adverse claims.

Guaranteed Delivery Procedures

If you wish to tender your Original Bonds but your Original Bonds are not immediately available or you cannot deliver your Original Bonds, the letter of transmittal or any other required documents to the exchange agent or comply with the procedures under DTC's automatic tender offer program in the case of Original Bonds, prior to the expiration date, you may still tender if:

- the tender is made through an eligible guarantor institution;
- prior to the expiration date, the exchange agent receives from such eligible guarantor institution, either a properly completed and duly executed notice of guaranteed delivery, by facsimile transmission, mail, or hand delivery or a properly transmitted agent's message and notice of guaranteed delivery, that (1) sets forth your name and address, the certificate number(s) of such Original Bonds and the principal amount of Original Bonds tendered; (2) states that the tender is being made thereby; and (3) guarantees that, within three New York Stock Exchange trading days after the expiration date, the letter of transmittal, or facsimile thereof, together with the Original Bonds or a book-entry confirmation, and any other documents required by the letter of transmittal, will be deposited by the eligible guarantor institution with the exchange agent; and
- the exchange agent receives the properly completed and executed letter of transmittal or facsimile thereof, with any required signature guarantees, as well as certificate(s) representing all tendered Original Bonds in proper form for transfer or a book-entry confirmation of transfer of the Original Bonds into the exchange agent's account at DTC and all other documents required by the letter of transmittal within three New York Stock Exchange trading days after the expiration date.

Upon request, the exchange agent will send to you a notice of guaranteed delivery if you wish to tender your Original Bonds according to the guaranteed delivery procedures.

Acceptance of Original Bonds for Exchange; Delivery of Exchange Bonds

Upon satisfaction or waiver of all of the conditions to each exchange offer, we will accept, promptly upon the expiration date, all the Original Bonds properly tendered and not validly withdrawn and will issue the Exchange Bonds promptly after acceptance of the Original Bonds. See “—Conditions to the Exchange Offers.”

For purposes of the exchange offers, we will be deemed to have accepted validly tendered Original Bonds for exchange if and when we give written notice to the exchange agent. The exchange agent will act as agent for the tendering holders for the purposes of receiving the Exchange Bonds from us and delivering Exchange Bonds to holders.

The holder of each Original Bond accepted for exchange will receive an Exchange Bond in an amount equal to the principal amount of the surrendered Original Bond. Holders of the Exchange Bonds on the record date for the first interest payment date following the consummation of the exchange offers will receive interest accruing from the most recent date to which interest has been paid on the corresponding Original Bonds. Holders of the Exchange Bonds will not receive any payment in respect of accrued interest on the Original Bonds otherwise payable on any interest payment date, the record date for which occurs on or after the consummation of the exchange offer. Interest on the Original Bonds accepted for exchange will cease to accrue upon the issuance of the Exchange Bonds.

In all cases, issuance of the Exchange Bonds for Original Bonds that are accepted for exchange will be made only after timely receipt by the exchange agent of an agent's message and a timely confirmation of book-entry transfer of the Original Bonds into the exchange agent's account at DTC. If a tender is made pursuant to a letter of transmittal, a holder must complete, sign and date the letter of transmittal, or a facsimile thereof; have the signatures guaranteed if required by the letter of transmittal; and mail or otherwise deliver the signed letter of transmittal or the signed facsimile, the Original Bonds and any other required documents to the exchange agent prior to 5:00 p.m., New York City time, on the expiration date.

If any tendered Original Bonds are not accepted for any reason set forth in the terms and conditions of the exchange offer, such unaccepted Original Bonds will be returned without expense to the holder or, in the case of Original Bonds tendered by book-entry transfer into the exchange agent's account at DTC pursuant to the book-entry procedures described below, an account maintained by the holder or on the holder's behalf with DTC promptly upon the expiration or termination of the corresponding exchange offer.

Book-Entry Transfers

Promptly after the date of this prospectus, the exchange agent will make a request to establish an account for each series of Original Bonds at DTC for purposes of the exchange offers. Any financial institution that is a participant in DTC's systems may make book-entry delivery of the Original Bonds by causing DTC to transfer those Original Bonds into the corresponding exchange agent's account at DTC in accordance with DTC's transfer procedures. This participant should transmit its acceptance to DTC on or prior to the relevant expiration date. DTC will verify this acceptance, execute a book-entry transfer of the tendered Original Bonds into the exchange agent's account at DTC and then send to the exchange agent confirmation of this book-entry transfer. A tender of Original Bonds through a book-entry transfer into the exchange agent's account will only be effective if an agent's message or the letter of transmittal with any required signature guarantees and any other required documents are transmitted to and received or confirmed by the exchange agent at the address set forth under "—Exchange Agent" prior to 5:00 p.m., New York City time, on the relevant expiration date. Delivery of documents to DTC in accordance with its procedures does not constitute delivery to the exchange agent.

Withdrawal Rights

You may withdraw your tender of Original Bonds at any time prior to 5:00 p.m., New York City time, on the relevant expiration date. For a withdrawal to be effective, the exchange agent must receive either:

- a valid withdrawal request through the DTC's Automated Tender Offer Program system from the tendering DTC participant before the expiration date. Any such request for withdrawal must include the VOI number of the tender to be withdrawn and the name of the ultimate beneficial owner of the related Original Bonds in order that such Original Bonds may be withdrawn; or
- a written notice of withdrawal from a holder, delivered to one of the addresses set forth under "—Exchange Agent," which includes a statement that such holder is withdrawing its Original Bonds and specifies (i) the name of the person having tendered the Original Bonds to be withdrawn; (ii) the Original Bonds to be withdrawn; and (iii) where certificates for the Original Bonds have been transmitted, the name in which such Original Bonds are registered, if different from that of the withdrawing holder. If certificates for Original Bonds have been delivered or otherwise identified to the exchange agent, then, prior to the release of such certificates, the withdrawing holder must also submit the serial numbers of the particular certificates to be withdrawn and a signed notice of withdrawal with signatures guaranteed by an eligible institution, unless such holder is an eligible institution.

Properly withdrawn Original Bonds may be retendered at any time prior to the expiration of the relevant exchange offer by following the procedures described under "—Procedures for Tendering Original Bonds."

We will determine all questions as to the validity, form and eligibility (including time of receipt) of notices of withdrawal. Any Original Bonds so withdrawn will be deemed not to have been validly tendered for exchange.

Conditions to the Exchange Offers

Despite any other term of the exchange offers, we are not be required to accept for exchange, or to issue Exchange Bonds in exchange for, any Original Bonds and we may terminate or amend either or both exchange offers as provided in this prospectus prior to the expiration date if in our reasonable judgment:

- the exchange offers or the making of any exchange by a holder violates any applicable law or interpretation of the staff of the SEC;

- any action or proceeding has been instituted or threatened in writing in any court or by or before any governmental agency with respect to the exchange offers that, in our judgment, would reasonably be expected to impair our ability to proceed with the exchange offers; or
- there has occurred: (i) any limitation by a governmental agency or authority which may adversely affect our ability to complete the transactions contemplated by the exchange offers, (ii) a declaration of a banking moratorium or any suspension of payments in respect to banks in the United States or any limitation by any governmental agency or authority which adversely affects the extension of credit, or (iii) a commencement of a war, armed hostilities or other similar international calamity directly or indirectly involving the United States, or, in the case of any of the foregoing existing at the time of the commencement of the exchange offer, a material acceleration or worsening thereof; which makes it inadvisable to proceed with the exchange offers.

We also expressly reserve the right to amend or terminate the exchange offers and to reject for exchange any Original Bonds not previously accepted for exchange, if we determine that any of the conditions of the exchange offers specified above have not been satisfied. We will give oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the Original Bonds as promptly as practicable. In the case of any extension, such notice will be issued no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled expiration date.

We reserve the right to waive any defects, irregularities or conditions to the exchange as to particular Original Bonds.

These conditions are for our benefit, and we may assert them regardless of the circumstances that may give rise to them or waive them in whole or in part at any or at various times prior to the expiration of the exchange offers in our reasonable discretion. If we fail at any time to exercise any of the foregoing rights, this failure will not constitute a waiver of such right. Each such right will be deemed an ongoing right that we may assert at any time or at various times prior to the expiration of the exchange offers.

In addition, we will not accept for exchange any Original Bonds tendered, and will not issue Exchange Bonds in exchange for any such Original Bonds, if at such time any stop order is threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the first mortgage indenture under the Trust Indenture Act of 1939, as amended.

Exchange Agent

We have appointed U.S. Bank Trust Company, National Association as the exchange agent for the exchange offers. U.S. Bank Trust Company also acts as trustee under the first mortgage indenture. You should direct all executed letters of transmittal and all questions and requests for assistance, requests for additional copies of this prospectus or of the letter of transmittal, or requests for notice of guaranteed delivery to the exchange agent addressed as follows:

By Registered or Certified Mail, Overnight Courier or Hand Delivery:
 U.S. Bank Trust Company, National Association
 Global Corporate Trust Services
 111 Fillmore Avenue E
 St. Paul, Minnesota 55107

By Facsimile:
(Eligible Institutions Only)
 (651) 466-5400
 Attention: Specialized Finance

Confirm by Telephone or for Information:
 (800) 934-6802

DELIVERY OF A LETTER OF TRANSMITTAL TO AN ADDRESS OTHER THAN AS SET FORTH ABOVE DOES NOT CONSTITUTE A VALID DELIVERY OF THE LETTER OF TRANSMITTAL.

Fees and Expenses

We will pay the exchange agent customary fees for its services, reimburse the exchange agent for its reasonable out-of-pocket expenses incurred in connection with the provision of these services and pay other registration and

exchange offer expenses, including registration and filing fees, fees and expenses of compliance with federal securities and state blue sky securities laws, printing expenses, messenger and delivery services and telephone fees and disbursements to our counsel, application and filing fees and any fees and disbursements to our independent certified public accountants. No dealer manager has been retained in connection with these exchange offers and we will not make any payment to brokers, dealers or others soliciting acceptances of the exchange offers.

This solicitation is being made primarily by electronic means. Additional solicitation may be made by telephone, facsimile or in person by our and our affiliates' officers and regular employees and by persons so engaged by the exchange agent.

Accounting Treatment

We will record the Exchange Bonds in our accounting records at the same carrying value as the Original Bonds which is the aggregate principal amount as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes upon the consummation of the exchange offer. The expenses of the exchange offers will be amortized over the term of the Exchange Bonds.

Transfer Taxes

You will not be obligated to pay any transfer tax in connection with the tender of the Original Bonds for the Exchange Bonds unless you instruct us to register Exchange Bonds in the name of, or request that Original Bonds not tendered or not accepted in the exchange offers be returned to, a person other than the registered tendering holder or unless a transfer tax is imposed for any reason other than the exchange of the Original Bonds in connection with the exchange offers. In those cases, the tendering holder will be responsible for the payment of any applicable transfer tax. If the tendering holder does not submit satisfactory evidence of payment of such taxes or exemption therefrom with the letter of transmittal, the amount of such transfer taxes will be billed to that tendering holder.

Consequences of Failure to Exchange

If you do not exchange your Original Bonds for Exchange Bonds under the exchange offers, your Original Bonds will remain subject to the restrictions on transfer of such Original Bonds:

- as set forth in the legend printed on the Original Bonds as a consequence of the issuance of the Original Bonds pursuant to the exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws; and
- as otherwise set forth in the offering memorandum distributed in connection with the private offering of the Original Bonds.

In general, you may not offer or sell your Original Bonds unless they are registered under the Securities Act or if the offer or sale is exempt from registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreements, we do not intend to register resales of the Original Bonds under the Securities Act.

DESCRIPTION OF THE EXCHANGE BONDS

General Description of the Exchange Bonds

The terms of the 2024A Exchange Bonds to be issued in the respective exchange offer are substantially identical to the 2024A Original Bonds, except that the 2024A Exchange Bonds will be registered under the Securities Act, and will not have transfer restrictions, registration rights or additional interest provisions. The 2024A Exchange Bonds will mature on June 1, 2054. We will pay interest on the 2024A Exchange Bonds at the annual rate of 5.800% (on the basis of a 360-day year of twelve 30-day months). Interest on the 2024A Exchange Bonds will accrue from the last date on which interest was paid on the 2024A Original Bonds, and is payable semi-annually on June 1 and December 1 of each year.

The terms of the 2025A Exchange Bonds to be issued in the respective exchange offer are substantially identical to the 2025A Original Bonds, except that the 2025A Exchange Bonds will be registered under the Securities Act, and will not have transfer restrictions, registration rights or additional interest provisions. The 2025A Exchange Bonds will mature on February 1, 2055. We will pay interest on the 2025A Exchange Bonds at the annual rate of 5.900% (on the basis of a 360-day year of twelve 30-day months). Interest on the 2025A Exchange Bonds will accrue from the last date on which interest was paid on the 2025A Original Bonds or the issuance date if no interest payment date has occurred, and is payable semi-annually on February 1 and August 1 of each year.

On each interest payment date, we will pay interest to the person in whose name the Exchange Bonds are registered at 5:00 P.M. New York City time on the regular record date for that interest payment, which is the 15th day (whether or not a business day) of the calendar month immediately preceding such interest payment date. If interest on the Exchange Bonds is not punctually paid or duly provided for, instead of paying such interest to the registered holders as of the regular record date, we will propose a new payment date and such interest will be paid to the registered holders of the Exchange Bonds as of a special record date, which will be no more than 15 days and no less than 10 days prior to the proposed payment date. If any interest payment date, redemption date or the maturity date of the Exchange Bonds falls on a day that is not a business day, the payment due on that interest payment date, redemption date or the maturity date will be made on the next business day, and without any interest or other payment in respect of such delay. Principal of, and premium (if any) and interest on, the Exchange Bonds will be payable, and the transfer of interests in the Exchange Bonds will be effected, through the facilities of DTC, as described under “– Book-Entry.” The Exchange Bonds will be issued in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof.

The Exchange Bonds will be registered in the name of Cede & Co., as nominee of DTC, pursuant to DTC’s book-entry system. Purchases of beneficial interests in the Exchange Bonds will be made in book-entry form, without certificates. If at any time the book-entry system is discontinued for the Exchange Bonds, the Exchange Bonds will be exchangeable for other fully registered certificated Exchange Bonds of like tenor and of an equal aggregate principal amount, in authorized denominations. See “– Book-Entry.” The trustee may impose a charge sufficient to reimburse us or the trustee for any tax, fee or other governmental charge required to be paid with respect to such exchange or any transfer of an exchange bond. The cost to us or the trustee, if any, of preparing each new exchange bond issued upon such exchange or transfer, and any other expenses incurred by us or the trustee in connection therewith, will be paid by the person requesting such exchange or transfer.

The Exchange Bonds will be issued pursuant to the same indenture as the Original Bonds. The Exchange Bonds will be secured by a first mortgage lien on substantially all our owned tangible and certain of our intangible property equally and ratably with all our other obligations issued under the first mortgage indenture, subject to certain exceptions and exclusions as described or referred to herein. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE—Security for Payment.”

Interest on the Exchange Bonds will be payable by check mailed to the registered owners thereof. However, interest on the Exchange Bonds will be paid to any holder of \$1,000,000 or more in aggregate principal amount of Exchange Bonds by wire transfer to a wire transfer address within the continental United States upon the written request of such holder received by the trustee not less than five days prior to the record date for the particular

interest payment. As long as the Exchange Bonds are registered in the name of Cede & Co., as nominee of DTC, such payments will be made directly to DTC. See “– Book-Entry.”

Redemption Provisions

At any time or from time to time before December 1, 2053 (the date six months prior to the maturity date of the 2024A Exchange Bonds), we may redeem the 2024A Exchange Bonds, in whole or in part at a “make-whole” redemption price equal to the greater of:

- 100% of the principal amount of the 2024A Exchange Bonds being redeemed; and
- the sum of the present values of the remaining principal and interest payments on the 2024A Exchange Bonds being redeemed that would be due if such 2024A Exchange Bonds matured on December 1, 2053 (excluding interest accrued and unpaid through the redemption date), discounted on a semi-annual basis (on the basis of a 360-day year of twelve 30-day months) at a rate equal to the sum of (i) the yield to maturity, determined on the third business day prior to the redemption date, of the U.S. Treasury security having a life equal to the remaining average life of the maturity of 2024A Exchange Bonds being redeemed (assuming for this purpose that the 2024A Exchange Bonds matured on December 1, 2053) and trading in the secondary market at the price closest to par, and (ii) 25 basis points,

plus in each case accrued and unpaid interest through the redemption date.

At any time or from time to time before August 1, 2054 (the date six months prior to the maturity date of the 2025A Exchange Bonds), we may redeem the 2025A Exchange Bonds, in whole or in part at a “make-whole” redemption price equal to the greater of:

- 100% of the principal amount of the 2025A Exchange Bonds being redeemed; and
- the sum of the present values of the remaining principal and interest payments on the 2025A Exchange Bonds being redeemed that would be due if such 2025A Exchange Bonds matured on August 1, 2054 (excluding interest accrued and unpaid through the redemption date), discounted on a semi-annual basis (on the basis of a 360-day year of twelve 30-day months) at a rate equal to the sum of (i) the yield to maturity, determined on the third business day prior to the redemption date, of the U.S. Treasury security having a life equal to the remaining average life of the maturity of 2025A Exchange Bonds being redeemed (assuming for this purpose that the 2025A Exchange Bonds matured on August 1, 2054) and trading in the secondary market at the price closest to par, and (ii) 20 basis points,

plus in each case accrued and unpaid interest through the redemption date.

If there is no U.S. Treasury security having a life equal to the remaining average life of the Exchange Bonds being redeemed, the discount rate will be calculated using a yield to maturity determined on a straight-line basis (rounding to the nearest calendar month, if necessary) from the average yield to maturity, determined on the third business day prior to the redemption date, of two U.S. Treasury securities having lives most closely corresponding to the remaining average life of the Exchange Bonds being redeemed and trading in the secondary market at the price closest to par.

At any time or from time to time on or after December 1, 2053 for the 2024A Exchange Bonds and August 1, 2054 for the 2025A Exchange Bonds, we may redeem the Exchange Bonds, in whole or in part at a redemption price equal to 100% of the principal amount of the Exchange Bonds being redeemed, plus accrued and unpaid interest thereon to, but excluding, the redemption date.

We must give at least 30 days’, but not more than 60 days’, prior notice of redemption mailed to the registered address of each holder of Exchange Bonds being redeemed except as otherwise required by the procedures of DTC. If less than all of the outstanding Exchange Bonds are to be redeemed, the Exchange Bonds to be redeemed will be selected by the trustee in any method it deems fair and appropriate, and the portion of the Exchange Bonds not so redeemed will be in a minimum denomination of \$2,000 and integral multiples of \$1,000 in excess thereof.

If at the time of mailing of notice for the optional redemption we have not deposited with the trustee moneys sufficient to redeem all of the Exchange Bonds called for redemption, the notice of optional redemption given by the trustee will so state and will further state that the redemption of the Exchange Bonds is conditional upon our providing, or causing to be provided, to the trustee, by 2:00 p.m. New York City time, on the redemption date, funds sufficient to effect the redemption, and the Exchange Bonds will not be redeemed unless such funds are deposited. The failure of the trustee to have sufficient funds to effect the redemption will not constitute a payment or other default by us under the first mortgage indenture and we will not be liable to any holder of those Exchange Bonds as a result of the failed redemption. If the trustee has enough designated funds on deposit to effect a redemption at the time we give notice of the redemption, then we are obligated to redeem the Exchange Bonds as provided in that notice.

Book-Entry

The certificates representing the Exchange Bonds will be issued in fully registered form, without interest coupons. The Exchange Bonds will be deposited with, or on behalf of, DTC, and registered in the name of Cede & Co., as DTC's nominee in the form of one or more global certificates. Upon the issuance of the global certificates, DTC or its nominee will credit, on its internal system, the respective principal amount of the individual beneficial interests represented by such global certificates to the accounts of persons who have accounts with such depository. Ownership of beneficial interests in a global certificate will be limited to persons who have accounts with DTC (participants) or persons who hold interests through participants. Ownership of beneficial interests in a global certificate will be shown on, and the transfer of that ownership will be effected only through, records maintained by DTC or its nominee (with respect to interests of participants) and the records of participants (with respect to interests of persons other than participants).

Investors that exchange Original Bonds for Exchange Bonds may also hold their interests directly through Clearstream Banking or Euroclear, if they are participants in such systems, or indirectly through organizations that are participants in such systems. Investors may also hold such interests through organizations other than Clearstream Banking or Euroclear that are participants in the DTC system. Clearstream Banking and Euroclear will hold interests in the global certificate representing Exchange Bonds on behalf of their participants through DTC.

So long as DTC, or its nominee, is the registered owner or holder of a global certificate, DTC or such nominee, as the case may be, will be considered the sole owner or holder of the Exchange Bonds represented by such global certificate for all purposes under the first mortgage indenture. No beneficial owner of an interest in a global certificate will be able to transfer the interest except in accordance with DTC's applicable procedures, in addition to those provided for under the first mortgage indenture and, if applicable, those of Euroclear and Clearstream Banking.

Payments of the principal of and interest on a global certificate will be made to DTC or its nominee, as the case may be, as the registered owner of the global certificate. Neither us, the trustee nor any paying agent will have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in a global certificate or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests. DTC or its nominee, upon receipt of any payment of principal or interest in respect of a global certificate, will credit participants' accounts with payments in amounts proportionate to their respective beneficial interests in the principal amount of such global certificate as shown on the records of DTC or its nominee. We also expect that payments by participants to owners of beneficial interests in such global certificate held through such participants will be governed by standing instructions and customary practices, as is now the case with securities held for the accounts of customers registered in the names of nominees for such customers. Such payments will be the responsibility of such participants.

Transfers between participants in DTC will be effected in the ordinary way in accordance with DTC rules. If a holder requires physical delivery of a certificated exchange bond for any reason, including to sell Exchange Bonds to persons in jurisdictions which require such delivery of such Exchange Bonds or to pledge such Exchange Bonds, the holder must transfer its interest in a global certificate in accordance with DTC's applicable procedures and the procedures set forth in the first mortgage indenture and, if applicable, those of Euroclear and Clearstream Banking. Because DTC can act only on behalf of participants in DTC, which in turn act on behalf of indirect participants, the

ability of a person having beneficial interests in a global certificate to pledge such interests to persons that do not participate in the DTC system, or otherwise take actions in respect of such interests, may be affected by the lack of a physical certificate evidencing such interests.

DTC will take any action permitted to be taken by a holder of Exchange Bonds (including the presentation of Exchange Bonds for exchange as described below) only at the direction of one or more participants to whose account the DTC interests in a global certificate is credited and only in respect of such portion of the aggregate principal amount of the Exchange Bonds as to which such participant or participants has or have given such direction. However, if there is an event of default under the Exchange Bonds, DTC will exchange a global certificate for certificated Exchange Bonds, which it will distribute to its participants.

DTC is a limited purpose trust company organized under the laws of the State of New York, a “banking organization” within the meaning of New York Banking Law, a member of the Federal Reserve System, a “clearing corporation” within the meaning of the Uniform Commercial Code and a “Clearing Agency” registered pursuant to the provisions of Section 17A of the Exchange Act. DTC was created to hold securities for its participants and facilitate the clearance and settlement of securities transactions between participants through electronic book-entry changes in accounts of its participants, thereby eliminating the need for physical movement of certificates. Participants include securities brokers and dealers, banks, trust companies and clearing corporations and may include certain other organizations. Indirect access to the DTC system is available to others such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a participant, either directly or indirectly (indirect participants). The rules applicable to DTC and its participants are on file with the SEC.

Although DTC, Euroclear and Clearstream Banking are expected to follow the foregoing procedures in order to facilitate transfers of interests in the Exchange Bonds represented by global certificates among their respective participants, they are under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued at any time. Neither we nor the trustee will have any responsibility for the performance by DTC, Euroclear or Clearstream Banking or their respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

If DTC is at any time unwilling or unable to continue as a depository for a global certificate and a successor depository is not appointed, we will issue certificated Exchange Bonds in exchange for a global certificate.

We will make all payments of principal and interest in immediately available funds.

The information in this subsection concerning DTC and DTC’s book-entry system has been obtained from sources that we believe to be reliable, but we do not take any responsibility for the accuracy of this information.

SUMMARY OF THE FIRST MORTGAGE INDENTURE

The Exchange Bonds will be secured under the first mortgage indenture on a parity basis with other obligations issued or to be issued under the first mortgage indenture. The following is a summary of selected provisions of the first mortgage indenture and is qualified in its entirety by reference to all of the provisions of the first mortgage indenture. The first mortgage indenture contains the full text of the provisions summarized in this section. You should read the first mortgage indenture, which is filed as an exhibit to the registration statement of which this prospectus forms a part and is also available for inspection at our principal office and the principal office of the trustee. Capitalized terms used in this section but not otherwise defined in this prospectus have the meaning set forth in the first mortgage indenture.

Security for Payment

The Exchange Bonds will be secured equally and ratably under the first mortgage indenture by 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, but excluding all excepted property and excludable property described below.

The first mortgage indenture does not include in the mortgaged property the following excepted property, among other things:

- cash on hand or in banks or in other financial institutions (excluding certain amounts deposited or required to be deposited with the trustee pursuant to the first mortgage indenture);
- other contracts and related accounts and contract rights not specifically subject to the lien of the first mortgage indenture;
- instruments and certain securities (other than those required to be deposited with the trustee under the first mortgage indenture);
- allowances for emissions or similar rights and credits;
- patents and trademarks;
- the right to bring an action or enforce a judgment;
- vehicles, vessels and airplanes;
- office furniture, equipment and supplies and data processing, accounting and other computer equipment, software and supplies;
- leases for a term of less than five years;
- timber, coal, ore, gas, oil and other minerals and all electric energy generated;
- non-assignable permits, licenses, franchises, leases, contracts and contractual and other rights;
- our interest in other property in which a security interest cannot legally be perfected; and
- all nuclear fuel, coal, oil and natural gas located outside of the State of Georgia.

The first mortgage indenture also excludes from mortgaged property excludable property, which is property as to which we have delivered to the trustee prior to acquiring such property a certificate stating that such property is to be excluded from the lien of the first mortgage indenture and that we would remain capable of meeting the rate covenant described below even if we do not have use of such property.

Our title to the mortgaged property and the lien of the first mortgage indenture are subject to permitted exceptions and encumbrances, which include, among other things, (i) identified exceptions and encumbrances existing in March 1997, as long as such matters do not materially impair the use of such property; (ii) non-delinquent or contested taxes; (iii) mechanics', materialmen's or contractors' liens; (iv) local improvement district assessments; (v) leases for a term of not more than ten years or, if for a term of more than ten years, leases which would not materially impair our use of the leased property in the conduct of our business; (vi) specified easements; (vii) the undivided interests of other co-owners in our facilities and liens on our undivided interests in co-owned facilities, and rights of such owners in property owned jointly with us; (viii) the pledge of current assets to secure current liabilities; (ix) liens which have been bonded for or for the payment of which a deposit had been made in the full amount of such lien; and (x) other exceptions and encumbrances which we do not believe adversely affect in any material respect our right to use our property to secure the Exchange Bonds. The lien of the first mortgage indenture is also shared with the trustee under the first mortgage indenture to secure and allow the trustee to recover amounts that may be owed to the trustee under the first mortgage indenture.

All of our property acquired after the date of this prospectus, other than excepted property and excludable property discussed above, will become subject to the lien of the first mortgage indenture, but subject to:

- permitted exceptions and specified purchase money and pre-existing liens;
- limitations, in the case of any consolidation, merger or sale of substantially all of our assets; and
- recordation of supplements to the first mortgage indenture describing that after-acquired property, in the case of real property.

Release and Substitution of Mortgaged Property

So long as no event of default exists under the first mortgage indenture, we will be able to sell, exchange or otherwise dispose of any part of the mortgaged property to facilitate our day-to-day operations. We may also release mortgaged property from the lien of the first mortgage indenture other than in connection with a sale, exchange or other disposition. In order to obtain a release of the mortgaged property from the trustee, we must find that the release will not impair the security under the first mortgage indenture and that the release is:

- (a) desirable in the conduct of our business and the property to be released is no longer necessary in the conduct of our business; or
- (b) made in lieu and reasonable anticipation of the taking of the property by eminent domain or the exercise by a governmental entity of a right to purchase or order the sale of the property.

Some of these releases also require the substitution of bondable additions, as defined in the first mortgage indenture, the deposit of cash with the trustee (which would constitute trust moneys as described below), the retirement or defeasance of first mortgage indenture obligations, or the deposit of designated qualifying securities with the trustee, in each case of equal value to the fair value of the mortgaged property to be released. Trust moneys can be withdrawn against bondable additions, retired or defeased first mortgage indenture obligations, or deposited designated qualifying securities, in each case of equal value, and can, at our option, be used for the redemption of first mortgage indenture obligations prior to their maturity, for the payment of principal on first mortgage indenture obligations at their maturity or for the purchase of first mortgage indenture obligations. To the extent that any trust moneys consist of the proceeds of insurance upon any part of the mortgaged property, those trust moneys can be withdrawn to reimburse us for costs to repair, rebuild or replace the destroyed or damaged property.

Trust moneys is all money received by the trustee:

- (a) upon the release of property from the lien of the first mortgage indenture, including all moneys received in respect of the principal of all purchase money obligations deposited with the trustee in respect of its release of property;
- (b) as compensation for, or proceeds of sale of, any part of the mortgaged property that has been taken by eminent domain or purchased by, or sold pursuant to an order of, a governmental authority;

- (c) as proceeds of insurance upon any part of the mortgaged property required to be paid to the trustee under the first mortgage indenture;
- (d) as principal paid on designated qualifying securities in excess of the principal then due on the first mortgage indenture obligations issued on the basis of the designated qualifying securities; or
- (e) for application as trust moneys under the first mortgage indenture or whose disposition was not otherwise specifically provided for in the first mortgage indenture.

Additional Obligations

The aggregate principal amount of obligations that may be issued under the first mortgage indenture is not limited. Additional first mortgage indenture obligations, ranking equally and ratably with the existing first mortgage indenture obligations, may be issued from time to time:

- (a) against:
 - (i) 90.91% of the amount of bondable additions,
 - (ii) the aggregate principal amount of retired or defeased first mortgage indenture obligations,
 - (iii) the aggregate principal amount of designated qualifying securities deposited with the trustee,
 - (iv) the amount of cash deposited with the trustee, and
 - (v) 80% of the amount of certified progress payments (discussed below); and
- (b) to evidence any reimbursement obligations that we have to Credit Enhancers (as defined herein), the Rural Utilities Service or the Department of Energy as a result of Credit Enhancement that we have obtained in connection with or guarantees of other first mortgage indenture obligations.

The amount of bondable additions available for the issuance of additional first mortgage indenture obligations is equal to (a) the existing balance of bondable additions, plus (b) the amount of property additions available to be certified to the trustee as bondable additions, less (c) the amount of retirements not yet counted in the calculation of bondable additions. Property additions are limited under the first mortgage indenture to certain of our property that is (i) chargeable to our fixed plant accounts and for which evidence of our title thereto is provided, (ii) subject to the lien of the first mortgage indenture, (iii) acquired or constructed by us since March 1, 1997, and (iv) not subject to pre-existing liens securing indebtedness prior to or on a parity with the lien of the first mortgage indenture. The amount of property additions available to be certified to the trustee is calculated as the lesser of the cost or fair value to us of such property additions (fair value to be determined as of the time of acquisition). Retirements consist of property subject to the lien of the first mortgage indenture that has been retired or otherwise disposed of free from the lien of the first mortgage indenture. The amount of retirements is (A) for retired property acquired by us after March 1, 1997, the lesser of the cost or fair value to us of such property (fair value to be determined as of the time of acquisition), and (B) for retired property acquired by us on or before March 1, 1997, the net book value of such property as of March 1, 1997. However, to the extent we establish a regulatory asset with respect to any bondable property and certain other conditions are met, we may defer the retirement of a portion of such bondable property until the end of the recovery period for such regulatory asset. Specifically, if our Board of Directors has approved the recovery in our rates of all or some portion of the value of property that would otherwise be considered retired under the first mortgage indenture in the form of a regulatory asset, such property would not be retired in an amount equal to the approved amount of the regulatory asset if (I) we obtain all required regulatory approvals for the regulatory asset accounting treatment, (II) we have in place power contracts with our members that have a term at least equal to the recovery period for the regulatory asset, and (III) we continue throughout the approved recovery period to meet the requirements of the rate covenant in the first mortgage indenture. We utilized this option in connection with the retirement of Plant Wansley in 2022 and expect to amortize the regulatory asset through 2040.

Designated qualifying securities are securities, including bonds or other debt instruments, held by the trustee and issued by one of our subsidiaries under an indenture, mortgage or other security instrument substantially

identical in substance to the provisions of our first mortgage indenture (subject to limited exceptions), which securities we have designated as (a) the basis for additional first mortgage indenture obligations, (b) the withdrawal of trust moneys, deposited cash or other specified assets held by the trustee, or (c) the release of mortgaged property. The aggregate amount of designated qualifying securities that can be deposited with the trustee at any time cannot exceed 20% of the aggregate principal amount of first mortgage indenture obligations then outstanding.

We may also use certified progress payments (as described below) as the basis for the issuance of additional first mortgage indenture obligations in order to finance the construction of generation and related facilities. Certified progress payments are payments we make pursuant to a qualified EPC contract (as defined below), which payments we are certifying as the basis for the issuance of additional first mortgage indenture obligations. These are amounts that we would assign to our fixed plant accounts and that will constitute property additions upon the performance of the qualified EPC contract. A qualified EPC contract is defined as any contract providing for the engineering, procurement or construction of generation or related facilities (including electric transmission and fuel supply facilities) that we intend to own upon performance of the qualified EPC contract, and the payments for which are used as the basis for the issuance of additional first mortgage indenture obligations. We can issue additional first mortgage indenture obligations up to 80% of the amount of the certified progress payments. The total amount of first mortgage indenture obligations outstanding at any time on the basis of certified progress payments may not exceed 40% of the total obligations then outstanding under the first mortgage indenture. Upon performance of the qualified EPC contract, we may convert the amounts outstanding under the first mortgage indenture obligations that were issued on the basis of certified progress payments, in an aggregate principal amount up to but not exceeding 90.91% of bondable additions acquired with the proceeds of certified progress payments and made the basis of such conversion, to amounts outstanding under first mortgage indenture obligations issued on the basis of bondable additions.

As of December 31, 2024, the amount of certified bondable additions and retired or defeased first mortgage indenture obligations available for the issuance of additional first mortgage indenture obligations was approximately \$3.4 billion. In addition, as of December 31, 2024, we had \$308.9 million of property additions and certified progress payments under qualified EPC contracts that, once certified to the trustee in accordance with the first mortgage indenture, will be available for the issuance of additional first mortgage indenture obligations.

Before we may issue additional first mortgage indenture obligations on the basis of bondable additions, retirements or defeasance of first mortgage indenture obligations, the deposit of cash with the trustee, the deposit of designated qualifying securities with the trustee, or certified progress payments, we must certify that our margins for interest ratio (as defined below) was at least 1.10 during the immediately preceding fiscal year or during any consecutive 12-month period within the 18-month period immediately preceding our request for additional first mortgage indenture obligations.

Covenants

Rate Covenant

The first mortgage indenture requires us to establish and collect rates for the use or the sale of the output, capacity or service of our properties that produce money sufficient, together with other money available to us, to enable us to comply with all covenants under the first mortgage indenture. Subject to any necessary approval or determination of any regulatory or judicial authority with jurisdiction over our rates, the first mortgage indenture requires us to establish and collect rates for the use or the sale of the output, capacity or service of our properties which are reasonably expected, together with our other revenue, to yield a margins for interest ratio equal to at least 1.10 for each fiscal year. The “margins for interest ratio” is the ratio of margins for interest for any period to total interest charges for that period. Margins for interest means, for any period, the sum of each of the following for that period:

- (a) our net margins (which includes our revenues subject to refund at a later date but excludes provisions for (i) non-recurring charges to income, including the non-recoverability of assets or expenses, except to the extent we determine to recover such charges in rates and (ii) refunds of revenues collected or accrued in any prior year subject to possible refund); plus

- (b) interest charges (discussed below); plus
- (c) any amount included in net margins for accruals for federal and state income and other taxes imposed on income after deduction of interest expense; plus
- (d) any amount included in net margins for any losses incurred by any subsidiary or affiliate of ours; plus
- (e) any amount we actually receive during that period as a dividend or other distribution of earnings of any subsidiary or affiliate of ours; minus
- (f) any amount included in net margins for any earnings or profits of any subsidiary or affiliate of ours; minus
- (g) any amount we actually contribute to the capital of, or actually pay under a guarantee of an obligation of, any subsidiary or affiliate to the extent of any accumulated losses incurred by the subsidiary or affiliate, but only to the extent (i) the losses have not otherwise caused other contributions or payments to be included in net margins for purposes of computing margins for interest for a prior period and (ii) the amount has not otherwise been included in net margins.

Interest charges means, for any period, our total interest charges (whether capitalized or expensed, provided that the payment of such charge is secured under the first mortgage indenture or any lien ranking prior to or on a parity with the lien of the first mortgage indenture, other than permitted exceptions and encumbrances) for the period with respect to interest accruing on all outstanding first mortgage indenture obligations and on all debt secured by a lien equal to or prior to the lien of the first mortgage indenture, but excludes interest accruing in respect of some first mortgage indenture obligations that were issued on the basis of designated qualifying securities.

Promptly upon any material change in the circumstances which were contemplated at the time the rates were most recently reviewed, but at least once every 12 months, we are required to review our rates and, subject to any necessary regulatory approval, promptly establish or revise our rates as necessary to comply with the foregoing requirements. However, if (i) upon any such review of our rates based on a material change in circumstances, we determine that rates are required to be established or revised in order for us to comply with the rate covenant, and (ii) there are less than 6 months remaining in the current fiscal year, it will satisfy the rate covenant if we establish or revise our rates for the next fiscal year so as to reasonably expect to meet the rate covenant for such next fiscal year. A failure by us to actually achieve a 1.10 margins for interest ratio will not itself constitute an event of default under the first mortgage indenture. However, a failure to establish rates reasonably expected to achieve a 1.10 margins for interest ratio will be an event of default if the failure continues for 45 days after we receive notice thereof from the trustee or the holders of at least 10% in principal amount of the first mortgage indenture obligations, unless the failure results from our inability to obtain regulatory approval. For 2025, our board of directors approved a budget to achieve a 1.10 margins for interest ratio, matching the minimum 1.10 ratio required by the first mortgage indenture. As our capital requirements continue to evolve, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

Limitation on Distributions, Payments or Retirement of Patronage Capital

The first mortgage indenture prohibits us from making any distribution, payment or retirement of patronage capital to our members if, at the time thereof or after giving effect thereto:

- (a) an event of default exists,
- (b) our aggregate margins and equities as of the end of the most recent fiscal quarter would be less than 20% of our total long-term debt and equities at such time, or
- (c) the aggregate amount expended for the distribution, payment or retirement on or after the date on which our aggregate margins and equities first reach 20% of our total long-term debt and equities would exceed 35% of our aggregate net margins earned after that date. The restrictions set forth in this clause (c) and in clause (b) above, however, would not apply if, after giving effect to the distribution, payment or retirement, our aggregate margins and equities as of the end of the most recent fiscal quarter would not be less than 30% of our total long-term debt and equities.

Limitation on Liens

The first mortgage indenture obligates us to keep all of the mortgaged property free and clear of other liens, subject to permitted exceptions and purchase money or pre-existing liens on our after-acquired property not in excess of 80% (or with respect to property that is not necessary to the operations of the remaining portion of our system, 100%) of the lesser of the cost or the fair value of the property and in the aggregate not in excess of 15% of the aggregate principal amount of all first mortgage indenture obligations.

Required Investment of Trust Moneys and Certain Cash

The first mortgage indenture requires us to invest or direct the trustee to invest at least 75% of each of (i) trust moneys and (ii) cash deposited under the first mortgage indenture, in:

- (a) defeasance securities;
- (b) securities issued by any agency or instrumentality of the United States of America or any corporation created pursuant to any act of the Congress of the United States;
- (c) commercial paper rated in either of the two highest rating categories by a national credit rating agency;
- (d) demand or time deposits, certificates of deposit and bankers' acceptances issued or accepted by any bank or trust company having capital surplus and undivided profits aggregating at least \$50 million and whose long-term debt is rated in any of the three highest rating categories by a national credit rating agency;
- (e) any non-convertible debt securities rated in any of the three highest rating categories by a national credit rating agency;
- (f) repurchase agreements that are secured by a perfected security interest in securities listed in clauses (a) or (b) above entered into with a government bond dealer recognized as a primary dealer by the Federal Reserve Bank of New York or any bank described in clause (d) above; or
- (g) any short-term institutional investment fund or account which invests solely in any of the foregoing obligations.

Consolidation, Merger, Conveyance or Transfer

The first mortgage indenture provides that we will not consolidate with or merge into any other person or convey or transfer the mortgaged property as an entirety to any person, unless:

- (a) the consolidation, merger, conveyance or transfer is on terms that fully preserve the lien and security of the first mortgage indenture as provided for in the first mortgage indenture and the rights and powers of the trustee and the holders of first mortgage indenture obligations;
- (b) the successor is a person organized and validly existing under the laws of the United States of America, any State of the United States of America or the District of Columbia;
- (c) the successor executes and delivers to the trustee a supplement to the first mortgage indenture in accordance with the requirements of the first mortgage indenture in which (i) the successor assumes the due and punctual payment of the principal of, and premium, if any, and interest on all the outstanding first mortgage indenture obligations and the performance and observance of every covenant and condition of the first mortgage indenture that we would otherwise have to perform or observe and (ii) there is a grant, conveyance, transfer and mortgage complying with the first mortgage indenture;
- (d) immediately after giving effect to the transaction, no event of default under the first mortgage indenture will exist; and
- (e) we deliver to the trustee an officers' certificate and an opinion of counsel, each of which state that such consolidation, merger, conveyance or transfer and the related supplement to the first mortgage indenture

comply with the requirements of the first mortgage indenture and that all conditions precedent provided for in the first mortgage indenture relating to the transaction have been complied with.

Credit Enhancement

The first mortgage indenture provides that first mortgage indenture obligations of any series may have the benefit of an insurance policy, letter of credit, financial guaranty insurance policy or other similar obligation to pay when due (to the extent not paid by us) the principal and interest on first mortgage indenture obligations or on another obligation the payment of which is secured by a first mortgage indenture obligation or credited against the principal and interest due on such first mortgage indenture obligation (each, a “Credit Enhancement”) issued by a credit enhancer (a “Credit Enhancer”). See “–Action by Credit Enhancer, the Rural Utilities Service or the Department of Energy.”

Events of Default and Remedies

Events of default under the first mortgage indenture consist of:

- (a) failure to pay principal of or premium, if any, on any first mortgage indenture obligation when due unless otherwise provided with respect to such first mortgage indenture obligation (we have provided for grace periods with respect to the payment of principal for certain first mortgage indenture obligations); provided, however, that no payment by the Rural Utilities Service pursuant to any guarantee by the United States of America, or pursuant to any Rural Utilities Service insuring of, or, unless otherwise provided in the obligation, by any other guarantor or insurer of, any first mortgage indenture obligation will be considered a payment under this paragraph for purposes of determining the existence of such a failure to pay;
- (b) failure to pay any interest on any first mortgage indenture obligation when due if the failure to pay is continued for 45 days unless otherwise provided with respect to such first mortgage indenture obligation (we have provided for shorter grace periods with respect to the payment of interest for certain first mortgage indenture obligations); provided, however, that no payment by the Rural Utilities Service pursuant to any guarantee by the United States of America, or pursuant to any Rural Utilities Service insuring of, or, unless otherwise provided in the obligation, by any other guarantor or insurer of, any first mortgage indenture obligation will be considered a payment under this paragraph for purposes of determining the existence of such a failure to pay;
- (c) default in the performance, or breach, by us of any of our warranties or covenants contained in the first mortgage indenture if the breach is continued for 45 days after written notice thereof from the trustee or the holders of at least 10% in principal amount of the outstanding first mortgage indenture obligations;
- (d) failure to pay when due (including any applicable grace period) any portion of principal (other than amounts due on acceleration) under any bond, debenture, note or other indebtedness for money borrowed (other than indebtedness secured by first mortgage indenture obligations), which failure has resulted in the acceleration of indebtedness in excess of \$25 million, if such indebtedness is not discharged or such acceleration is not rescinded or annulled within 10 days after the failure or acceleration;
- (e) a judgment against us in excess of \$25 million which remains unsatisfied or unstayed for 45 days after either entry of judgment or termination of stay, and such judgment remains unstayed or unsatisfied for a period of 10 days after notice thereof from the trustee or the holders of at least 10% in principal amount of the outstanding first mortgage indenture obligations; or
- (f) other proceedings in bankruptcy, receivership, insolvency, liquidation or reorganization.

Subject to the provisions of the first mortgage indenture relating to the duties of the trustee, if an event of default occurs and is continuing, the trustee will be under no obligation to exercise any of its rights or powers under the first mortgage indenture at the request or direction of any of the holders, unless those holders (other than the United States of America or its agencies or instrumentalities) have offered to the trustee reasonable indemnity. Subject to provisions for the indemnification of the trustee, the holders of a majority in aggregate principal amount

of the outstanding first mortgage indenture obligations will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the trustee or exercising any trust or power conferred on the trustee, except that, so long as it is not in default with respect to its Credit Enhancement for any first mortgage indenture obligations, a Credit Enhancer for, and not the actual holders of, those first mortgage indenture obligations would be deemed to be the holder of those first mortgage indenture obligations for purposes of, among other things, taking action in connection with the remedies set forth in the first mortgage indenture.

If an event of default occurs and is continuing, either the trustee or the holders of at least 25% in aggregate principal amount of the outstanding first mortgage indenture obligations may accelerate the maturity of all first mortgage indenture obligations. However, after the acceleration, but before a sale of any of the mortgaged property or a judgment or decree based on acceleration, the holders of a majority in aggregate principal amount of outstanding first mortgage indenture obligations may, under certain circumstances, rescind the acceleration if all events of default, other than the non-payment of accelerated principal, have been cured or waived as provided in the first mortgage indenture.

No holder of any first mortgage indenture obligation has any right to institute any proceeding with respect to the first mortgage indenture or for any remedy thereunder, unless:

- (a) the holder has previously given to the trustee written notice of a continuing event of default;
- (b) the holders of at least 25% in aggregate principal amount of the outstanding first mortgage indenture obligations have made written request to the trustee to institute the proceeding as trustee;
- (c) the holders (other than the United States of America or its agencies or instrumentalities) have offered reasonable indemnity to the trustee against the costs to be incurred in compliance with the request;
- (d) the trustee for 60 days after its receipt of such notice, request and indemnity has failed to institute the proceeding; and
- (e) the trustee has not received from the holders of a majority in aggregate principal amount of the outstanding first mortgage indenture obligations a direction inconsistent with the request.

However, the limitations on the holders' rights to institute proceedings do not apply to a suit instituted by a holder of a first mortgage indenture obligation for the enforcement of payment of the principal of and premium, if any, or interest on the first mortgage indenture obligation on or after the respective due dates stated therein.

The first mortgage indenture provides that the trustee, within 90 days after the occurrence of the event of default (but at least 60 days after the occurrence of some specified events of default), will give to the holders of first mortgage indenture obligations notice of all uncured defaults known to it, provided that, except that in the case of a default in the payment of principal of, and premium, if any, or interest on any first mortgage indenture obligations, the trustee will be protected in withholding that notice if it in good faith determines that the withholding of that notice is in the interest of the holders of the first mortgage indenture obligations.

If an event of default occurs and is continuing, the trustee may sell the mortgaged property, in either judicial or nonjudicial proceedings. The proceeds from the disposition of the mortgaged property will be applied as follows:

- (a) *first*, to the payment of all amounts due to the trustee;
- (b) *second*,
 - (i) if all first mortgage indenture obligations have become due and payable, to the payment of outstanding first mortgage indenture obligations without preference or priority between interest, principal and redemption price, including premium, if any, among first mortgage indenture obligations, or
 - (ii) if the principal of all first mortgage indenture obligations have not become due and payable, then (A) first to interest installments in the order of their maturity and (B) second to principal or redemption price;

- (c) *third*, to the payment of penalties, costs and expenses associated with first mortgage indenture obligations;
- (d) *fourth*, to payment of amounts to maintain the value of any reserve funds relating to tax exempt bonds; and
- (e) *fifth*, to us or whoever may be lawfully entitled to receive any remaining amount.

The first mortgage indenture requires us to deliver to the trustee, within 120 days after the end of each calendar year, a written statement as to our compliance (determined without regard to any grace period or notice requirement) with all of our obligations under the first mortgage indenture. In addition, we are required to deliver to the trustee, promptly after any of our officers may be reasonably deemed to have knowledge of a default under the first mortgage indenture, a written notice specifying the nature and duration of the default and the action we are taking and propose to take with respect to the default.

Amendments and Supplements to the First Mortgage Indenture

Waiver of Covenants

Our compliance with the covenants contained in the first mortgage indenture relating to (i) limitation on liens, (ii) payment of taxes, (iii) maintenance of properties, (iv) insurance, (v) delivery of annual compliance certificates and notices of default under the first mortgage indenture, (vi) establishing and reviewing certain rates, (vii) distributions to our members and (viii) investment of certain moneys, may be waived by a vote of the holders of a majority of the aggregate principal amount of the outstanding first mortgage indenture obligations.

Supplements to the First Mortgage Indenture without Consent of Holders

Without the consent of the holders of any first mortgage indenture obligations, we and the trustee may, from time to time, enter into one or more supplements to the first mortgage indenture:

- (a) to correct or amplify the description of any property at any time subject to the lien of the first mortgage indenture;
- (b) to confirm property subject or required to be subjected to the lien of the first mortgage indenture or to subject additional property to the lien of the first mortgage indenture;
- (c) to add to the conditions, limitations and restrictions on the authorized amount, terms or purposes of the issue, authentication and delivery of first mortgage indenture obligations or of any series of first mortgage indenture obligations;
- (d) to create any new series of first mortgage indenture obligations;
- (e) to modify or eliminate any of the terms of the first mortgage indenture, provided in the event the modification or elimination would adversely affect or diminish the rights of any holder, the supplement to the first mortgage indenture must state that any such modification or elimination will become effective only when there are no first mortgage indenture obligations outstanding under any series created prior to the supplement to the first mortgage indenture and provided the trustee may decline to execute the supplement to the first mortgage indenture if, in the trustee's opinion, it does not afford adequate protection to the trustee;
- (f) to evidence the succession of another corporation to us and the assumption by any such successor of our covenants;
- (g) to add to our covenants or events of default for the benefit of the holders of all or any series of first mortgage indenture obligations or to surrender any of our rights or powers;
- (h) to evidence the succession of another trustee or the appointment of a co-trustee or separate trustee;
- (i) to cure any ambiguity, to correct or supplement any provision in the first mortgage indenture which may be inconsistent with any other provision or to make any other provision, with respect to matters or questions

arising under the first mortgage indenture, which is not inconsistent with the provisions of the first mortgage indenture, provided such action shall not, in our opinion, adversely affect the interests of the holders of the first mortgage indenture obligations in any material respect;

- (j) to modify, eliminate or add to the provisions of the first mortgage indenture to the extent necessary to effect the qualification of the first mortgage indenture under the Trust Indenture Act of 1939 or under any similar federal statute hereafter enacted;
- (k) to add or change any provision of the first mortgage indenture to the extent necessary to permit or facilitate the issuance of first mortgage indenture obligations in bearer or book-entry form; or
- (l) to make any change in the first mortgage indenture that, in the reasonable judgment of the trustee, would not materially and adversely affect the rights of holders of first mortgage indenture obligations.

A supplement to the first mortgage indenture will be presumed not to materially and adversely affect the rights of holders for purposes of paragraph (l) above if (i) the first mortgage indenture, as supplemented and amended, secures equally and ratably the payment of principal of (and premium, if any) and interest on the first mortgage indenture obligations which are to remain outstanding and (ii) we furnish to the trustee written evidence from at least two nationally recognized statistical rating organizations then rating the first mortgage indenture obligations (or other obligations primarily secured by first mortgage indenture obligations) that their respective underlying ratings of the first mortgage indenture obligations (or other obligations primarily secured by first mortgage indenture obligations) will not be withdrawn or reduced as a result of the changes in the first mortgage indenture effected by the supplement to the first mortgage indenture, provided that any changes in the first mortgage indenture that require the consent of all of the holders of first mortgage indenture obligations affected thereby may not be made on the basis that they do not materially and adversely affect the rights of holders.

Supplements to the First Mortgage Indenture with Consent of Holders

With the consent of the holders of not less than a majority in principal amount of the first mortgage indenture obligations of all series then outstanding affected by the supplement to the first mortgage indenture, we and the trustee may, from time to time, enter into one or more supplements to the first mortgage indenture to add, change or eliminate any of the provisions of the first mortgage indenture or modify the rights of the holders of the first mortgage indenture obligations. However, no supplement to the first mortgage indenture will, without the consent of the holder of each outstanding first mortgage indenture obligation affected thereby:

- (a) change the stated maturity (the date specified in each first mortgage indenture obligation as the date on which the principal of the first mortgage indenture obligation or an installment of interest on any first mortgage indenture obligation is due and payable) of any first mortgage indenture obligation;
- (b) reduce the principal of, or any installment of interest on, any first mortgage indenture obligation, or any premium payable upon the redemption of the first mortgage indenture obligation;
- (c) change any place of payment (the city or political subdivision thereof in which we are required by the first mortgage indenture to maintain an office or agency for payment of the principal of or interest on the first mortgage indenture obligations) where, or the currency in which, any first mortgage indenture obligation, or the interest thereon, is payable;
- (d) impair the right to institute suits for the enforcement of any payment on or after the stated maturity thereof (or, in the case of redemption, on or after the redemption date);
- (e) reduce the percentage in principal amount of the outstanding first mortgage indenture obligations, the consent of the holders of which is required for various purposes;
- (f) permit the creation of any lien ranking prior to or on a parity with the lien of the first mortgage indenture with respect to any of the mortgaged property;

- (g) modify the provisions of any mandatory sinking fund so as to affect the rights of a holder to the benefits of the mandatory sinking fund; or
- (h) modify certain other provisions of the first mortgage indenture.

Action by Credit Enhancer, the Rural Utilities Service or the Department of Energy

Under the first mortgage indenture, any Credit Enhancer that agrees to provide any undertaking to pay amounts due with respect to any first mortgage indenture obligations to the extent those amounts are not paid by us will be considered a holder of those first mortgage indenture obligations for the purpose of (i) giving any requisite approval or consent to supplements or amendments to the first mortgage indenture (other than those amendments which require the consent of the holders of each first mortgage indenture obligation affected thereby) and (ii) giving any other approval or consent, giving any notice, effecting any waiver or authorization, exercising any remedies or taking any other action that can be taken by the holder of those first mortgage indenture obligations. However, if the Credit Enhancer is in default with respect to the performance of its undertaking, it will not be considered a holder in place of the holders of those first mortgage indenture obligations.

With respect to first mortgage indenture obligations guaranteed or insured by the United States of America, acting by and through the Administrator of the Rural Utilities Service, the Rural Utilities Service, rather than the actual payee of the first mortgage indenture obligations, will have all of the rights of a holder of the first mortgage indenture obligations for the period in which those first mortgage indenture obligations are guaranteed or insured by the United States of America, acting by and through the Administrator of the Rural Utilities Service, regardless of whether the Rural Utilities Service actually possesses those first mortgage indenture obligations. All the applicable first mortgage indenture obligations must be registered to show the United States of America, acting by and through the Administrator of the Rural Utilities Service, as the registered holder of the first mortgage indenture obligations, unless the Rural Utilities Service otherwise requests.

With respect to first mortgage indenture obligations guaranteed or insured by the U.S. Department of Energy, acting through the Secretary of Energy (or appropriate representative thereof), the U.S. Department of Energy, rather than the actual payee of the first mortgage indenture obligations, will have all of the rights of a holder of the first mortgage indenture obligations for the period in which those first mortgage indenture obligations are guaranteed or insured by the U.S. Department of Energy, acting through the Secretary of Energy (or appropriate representative thereof), regardless of whether the U.S. Department of Energy actually possesses those first mortgage indenture obligations. All the applicable first mortgage indenture obligations must be registered to show the U.S. Department of Energy, acting through the Secretary of Energy (or appropriate representative thereof), as the registered holder of the first mortgage indenture obligations, unless the U.S. Department of Energy otherwise requests.

Defeasance

Subject to some conditions, the first mortgage indenture provides that first mortgage indenture obligations of any series, or any maturity within a series, will be deemed to have been paid and our obligations to the holders of those first mortgage indenture obligations will be discharged, if we deposit with the trustee or paying agent cash or defeasance securities maturing as to principal and interest in such amounts and at such times as are sufficient, without consideration of reinvestment of such interest, to pay when due the principal or (if applicable) redemption price and interest due and to become due on those first mortgage indenture obligations. Defeasance securities include non-callable bonds or other obligations, the principal and interest on which constitute direct obligations of, or are unconditionally guaranteed by, the United States of America, or certificates of interest or participation in any of these obligations, or in specified portions of these obligations (which may consist of specified portions of the interest on the certificates).

Concerning the Trustee

U.S. Bank Trust Company, National Association is the trustee under the first mortgage indenture and is also serving as exchange agent in connection with the exchange offer. We may maintain other banking relationships in the ordinary course of business with U.S. Bank Trust Company for which it may receive customary fees.

Governing Law

The first mortgage indenture and the Exchange Bonds are governed by and construed in accordance with the laws of the State of Georgia.

SUMMARY OF MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

We are subject to United States federal and state corporate income taxation but, as a cooperative, we are allowed a deduction for patronage sourced dividends that we allocate to our members. We are, however, liable for United States federal and state income taxes on that portion of our taxable income which is not derived from patronage sources, and we are entitled to no special deduction with respect to our non-patronage sourced taxable income. Due to the availability of the special deduction for patronage sourced dividends that we allocate to our members, we do not anticipate that the amount of our United States federal and state corporate income taxes will be material in the foreseeable future.

Like any corporation, the relevant taxing authorities may challenge how we treat certain items on our tax returns. Because we are a cooperative, these authorities may also challenge our classification of items of income and expense between patronage and non-patronage sources. If, in any year, the relevant authorities were to reclassify any of our patronage sourced income as non-patronage sourced, or any of our non-patronage sourced expenses as patronage sourced, it is possible that we might owe income taxes in that year and the amount of those income taxes might be material.

Exchange Offers

The exchange of the Original Bonds for Exchange Bonds pursuant to the exchange offers should not be treated as a taxable event for United States federal income tax purposes because the Exchange Bonds will not differ materially in kind or extent from the Original Bonds, with the result that the holding period for your Exchange Bonds will include the holding period of the Original Bonds you surrender in exchange therefor, and the basis of your Exchange Bonds will be the same as the basis of the Original Bonds you surrender in exchange (as determined immediately prior to the date of exchange).

In any event, persons considering the exchange of Original Bonds for Exchange Bonds should consult their own tax advisors concerning the United States federal income tax consequences in light of their particular situations as well as any consequences arising under the laws of any other taxing jurisdiction.

Tax Considerations Applicable to Holders of the Exchange Bonds

The following is a summary of certain United States federal income tax consequences relating to the ownership and disposition of the Exchange Bonds by an initial beneficial holder of the Original Bonds who purchased the Original Bonds for cash at the original offering price, exchanges its Original Bonds for Exchange Bonds pursuant to the exchange offer, and who holds the bonds as capital assets within the meaning of section 1221 of the Internal Revenue Code of 1986 (the Code).

This section does not apply to you if you are subject to special tax rules, such as those that apply to:

- brokers and dealers;
- traders in securities that elect to mark to market;
- banks;
- certain former citizens or residents of the United States;
- life insurance companies, real estate investment trusts and regulated investment companies;
- individual retirement accounts and other tax-deferred accounts;
- tax-exempt organizations;
- persons who will hold the Exchange Bonds as part of a hedging, straddle, integrated or conversion transaction;
- grantor trusts;

- S corporations;
- certain U.S. Holders that use the accrual method of accounting for United States federal income tax purposes and are required to prepare certified financial statements or file financial statements with certain regulatory or governmental agencies;
- “controlled foreign corporations” or “passive foreign investment companies” for United States federal income tax purposes; or
- persons whose functional currency for United States federal income tax purposes is not the U.S. dollar.

Finally, this section does not address any foreign, state or local tax issues or any United States federal estate, gift or alternative minimum tax issues. This discussion is based upon the Code, existing and proposed United States Treasury Regulations and judicial decisions and administrative interpretations thereof, all as of the date of this prospectus and all of which are subject to change, possibly with retroactive effect, or to different interpretations. We cannot assure you that the Internal Revenue Service will not challenge one or more of the tax consequences described in this section. We have not obtained, nor do we intend to obtain, a ruling from the IRS or an opinion of counsel with respect to the United States federal tax consequences of exchanging, owning or disposing of the bonds.

As used herein, “U.S. Holder” means a beneficial owner of a bond that is:

- an individual citizen or resident of the United States for United States federal income tax purposes;
- a corporation or other entity taxable as a corporation created or organized in or under the laws of the United States or any state thereof (including the District of Columbia);
- an estate, the income of which is subject to United States federal income taxation regardless of its source; or
- a trust, where a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons (as defined in the Internal Revenue Code of 1986, as amended) have the authority to control all substantial decisions of the trust (or a trust that has made a valid election under U.S. Treasury Regulations to be treated as a domestic trust).

A “Non-U.S. Holder” generally means any owner (or beneficial owner) of an exchange bond that is not a U.S. Holder and is not a partnership for United States federal income tax purposes. If a partnership holds bonds, the tax treatment of such partnership or a partner in such partnership generally will depend upon the status of the partner and upon the activities of the partnership. Partnerships and partners of partnerships holding bonds should consult their own tax advisors regarding the tax consequences of an investment in the Exchange Bonds (including their status as U.S. Holders or Non-U.S. holders).

U.S. Holders

Interest

The Original Bonds were not issued with original issue discount for United States federal income tax purposes. As a result, you will be taxed on interest on the Exchange Bonds when it is received or accrued (depending upon your method of tax accounting).

Sale or Exchange of Exchange Bond

Upon a sale, exchange (other than in connection with the Exchange Offer) or redemption of a Bond, you generally will recognize gain or loss equal to the difference between the amount realized on the sale (not including any amounts attributable to accrued and unpaid interest, which will be taxed in the manner described above under the heading “*Interest*”) and your adjusted United States federal income tax basis in the Bond. Except to the extent attributable to accrued but unpaid interest, any gain or loss you recognize on the sale of a Bond should generally be capital gain or loss.

We may deposit with the trustee or paying agent cash or defeasance securities in amounts sufficient to cause the Exchange Bonds to be deemed under the first mortgage indenture to have been paid. See “SUMMARY OF THE FIRST MORTGAGE INDENTURE – Defeasance.” For United States federal income tax purposes, such a defeasance generally will result in you being deemed to have exchanged your Exchange Bonds for reissued Exchange Bonds, and you may recognize gain or loss on such deemed exchange, without any corresponding receipt of money. Ownership of an Exchange Bond subsequent to any such defeasance may have tax consequences different from those described in this section, and you should consult with your own tax advisor regarding the tax consequences to you of a defeasance of the Exchange Bonds.

Medicare Tax

Certain non-corporate U.S. Holders will be subject to a 3.8% tax on the lesser of (1) the U.S. Holder’s “net investment income” (in the case of individuals) or “undistributed net investment income” (in the case of estates and trusts (other than grantor trusts)) for the relevant taxable year and (2) the excess of the U.S. Holder’s “modified adjusted gross income” (in the case of individuals) or “adjusted gross income” (in the case of estates and trusts (other than grantor trusts)) for the taxable year over a certain threshold (which in the case of individuals will be between \$125,000 and \$250,000, depending on the individual’s circumstances). A U.S. Holder’s calculation of net investment income generally will include amounts treated as interest that are received on the Exchange Bonds and its net gains from the disposition of the Exchange Bonds, unless such interest or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). If you are a non-corporate U.S. Holder, you should consult your own tax advisor regarding the applicability of this tax to your income and gains in respect of your investment in the Exchange Bonds.

Non-U.S. Holders

If you are a Non-U.S. Holder, subject to the discussions under the headings “Backup Withholding and Information Reporting for U.S. and Non-U.S. Holders” and “Foreign Account Tax Compliance Act” below, interest paid to you in respect of the Exchange Bonds generally should not be subject to United States federal income or withholding tax provided that:

- such interest is not effectively connected with your conduct of a trade or business in the United States;
- you do not actually or constructively own 10% or more of the total combined voting power of all classes of our stock entitled to vote;
- you are not a controlled foreign corporation that is related directly or constructively to us through stock ownership;
- you are not a bank that acquired the Exchange Bonds in consideration for an extension of credit made pursuant to a loan agreement entered into in the ordinary course of your trade or business; and
- you timely and properly provide the withholding agent with a statement to the effect that you are not a U.S. person (generally through the provision of a properly executed appropriate IRS Form W-8).

Similarly, if you are a Non-U.S. Holder, subject to the discussions under the headings “Backup Withholding and Information Reporting for U.S. and Non-U.S. Holders” and “Foreign Account Tax Compliance Act” below, any gain recognized by you in connection with a sale, exchange or redemption of your Exchange Bonds generally should not be subject to United States federal income or withholding tax provided that:

- such gain is not effectively connected with your conduct of a trade or business in the United States; and
- if you are an individual, you are not present in the United States for 183 days or more in the taxable year of the sale or other disposition and certain other conditions are met.

If you fail to satisfy any of the provisos set forth above, the interest you receive on the Exchange Bonds and/or the gain you recognize on a sale or disposition of the Exchange Bonds may be subject to United States federal

income tax, and you should consult your own tax advisor as to the United States federal income tax consequences applicable to your acquisition, ownership and disposition of the Exchange Bonds.

Backup Withholding and Information Reporting for U.S. and Non-U.S. Holders

Information reporting to the IRS may be required with respect to payments on the Exchange Bonds, and with respect to proceeds from the sale of the Exchange Bonds, held by holders other than corporations and certain other exempt recipients. A “backup” withholding tax may also apply to those payments if you fail to provide certain identifying information (such as your taxpayer identification number or an attestation to your status as a Non-U.S. Holder). Backup withholding is not an additional tax and may be refunded (or credited against your United States federal income tax liability, if any) provided that certain required information is furnished to the IRS in a timely manner.

Foreign Account Tax Compliance Act

The Foreign Account Tax Compliance provisions of the Code (generally referred to as “FATCA”), when applicable, impose a United States federal withholding tax of 30% on certain payments on, and the gross proceeds from the sale or other disposition of, obligations that produce U.S. source income to foreign financial institutions and certain other non-U.S. entities unless certain information reporting and certification requirements have been satisfied. The obligation to withhold under FATCA, if applicable, will apply to payments of interest made on the Exchange Bonds. Under proposed Treasury regulations, the requirement under FATCA to withhold on gross proceeds from the sale, exchange, redemption or other disposition of the Exchange Bonds would be eliminated, and withholding under FATCA on certain foreign pass-through payments would not be required until two years after the date that final regulations defining the term foreign pass-through payment are issued. The U.S. Treasury Department has indicated that taxpayers may rely on these proposed regulations pending their finalization.

Holders are encouraged to consult with their own tax advisors regarding the effects of FATCA on their investment in the Exchange Bonds.

THIS DISCUSSION IS FOR GENERAL INFORMATION ONLY AND IS NOT INTENDED TO CONSTITUTE A COMPLETE DESCRIPTION OF ALL TAX CONSIDERATIONS RELATING TO THE EXCHANGE, OWNERSHIP AND DISPOSITION OF THE ORIGINAL BONDS OR THE EXCHANGE BONDS. YOU SHOULD CONSULT YOUR OWN TAX ADVISOR AS TO THE PARTICULAR TAX CONSEQUENCES TO YOU OF THE EXCHANGE, OWNERSHIP AND DISPOSITION OF THE ORIGINAL BONDS OR THE EXCHANGE BONDS, INCLUDING THE EFFECT AND APPLICABILITY OF STATE, LOCAL, OR FOREIGN TAX LAWS OR TAX TREATIES AND THE POSSIBLE EFFECTS OF CHANGES IN THE TAX LAW.

PLAN OF DISTRIBUTION

Each broker-dealer that receives Exchange Bonds for its own account pursuant to the exchange offers must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Bonds. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Bonds received in exchange for Original Bonds where such Original Bonds were acquired as a result of market-making activities or other trading activities. We have agreed to keep effective the registration statement of which this prospectus is a part until the earlier of 180 days after the completion of the relevant exchange offer or such time as broker-dealers no longer own any Exchange Bonds. In addition, all dealers effecting transactions in the Exchange Bonds may be required to deliver a prospectus.

We will not receive any proceeds from any sale of Exchange Bonds by broker-dealers. Exchange Bonds received by broker-dealers for their own account pursuant to the exchange offers may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the Exchange Bonds or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer and/or the purchasers of any such Exchange Bonds. Any broker-dealer that resells Exchange Bonds that were received by it for its own account pursuant to the exchange offers and any broker or dealer that participates in a distribution of such Exchange Bonds may be deemed to be an “underwriter” within the meaning of the Securities Act, and any profit of any such resale of Exchange Bonds and any commission or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that, by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act.

For a period of 180 days after the expiration date of the relevant exchange offer (or until the broker-dealer no longer holds registrable securities), we will promptly send additional copies of this prospectus and any amendments or supplements to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. Subject to certain limitations set forth in the registration rights agreements, we have agreed to pay all expenses incident to the exchange offers other than commissions or concessions of any broker-dealer and will indemnify you (including any broker-dealers) against certain liabilities under the Securities Act.

LEGAL MATTERS

The validity and enforceability of the Exchange Bonds will be passed upon for us by Eversheds Sutherland (US) LLP.

EXPERTS

The consolidated financial statements of Oglethorpe Power Corporation at December 31, 2024 and 2023, and for each of the three years in the period ended December 31, 2024, appearing in this Prospectus and Registration Statement have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

AVAILABLE INFORMATION

We have filed with the SEC a registration statement on Form S-4 under the Securities Act with respect to the Exchange Bonds. This prospectus, which forms a part of the registration statement, does not contain all of the information set forth in the registration statement. For further information with respect to us and the Exchange Bonds, reference is made to the registration statement. Statements contained in this prospectus as to the contents of any contract or other document are not necessarily complete.

We have historically filed, on a voluntary basis, annual, quarterly and current reports and other information with the SEC. You may read and copy any document we have or will file with the SEC at the SEC public website (<http://www.sec.gov>).

You should rely only upon the information provided in this prospectus. We have not authorized anyone to provide you with different information. You should not assume that the information in this prospectus is accurate as of any date other than the date of this prospectus.

APPENDIX A—AUDITED FINANCIAL STATEMENTS

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OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF REVENUES AND EXPENSES

For the years ended December 31, 2024, 2023 and 2022

	(dollars in thousands)		
	2024	2023	2022
Operating revenues:			
Sales to members	\$ 2,145,522	\$ 1,681,566	\$ 1,974,683
Sales to non-members	36,325	58,619	155,454
Total operating revenues	2,181,847	1,740,185	2,130,137
Operating expenses:			
Fuel	\$ 612,440	\$ 578,794	\$ 1,045,089
Production	524,355	413,312	468,754
Depreciation and amortization	411,598	330,449	283,774
Purchased power	80,735	74,657	82,516
Accretion	69,223	65,907	55,953
Total operating expenses	\$ 1,698,351	\$ 1,463,119	\$ 1,936,086
Operating margin	\$ 483,496	\$ 277,066	\$ 194,051
Other income:			
Investment income	\$ 56,282	\$ 70,252	\$ 57,564
Amortization of deferred gains	1,789	1,789	1,789
Allowance for equity funds used during construction	1,756	750	700
Other	7,563	8,258	12,191
Total other income	\$ 67,390	\$ 81,049	\$ 72,244
Interest charges:			
Interest expense	\$ 521,525	\$ 515,862	\$ 455,474
Allowance for debt funds used during construction	(52,352)	(234,090)	(262,573)
Amortization of debt discount and expense	11,212	10,553	11,690
Net interest charges	\$ 480,385	\$ 292,325	\$ 204,591
Net margin	\$ 70,501	\$ 65,790	\$ 61,704

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31, 2024 and 2023

	(dollars in thousands)	
	2024	2023
Assets		
Electric plant:		
In service	\$ 17,388,476	\$ 14,112,098
Right-of-use assets--finance leases	302,732	302,732
Less: Accumulated provision for depreciation	(5,701,627)	(5,418,738)
Electric plant in service, net	11,989,581	8,996,092
Nuclear fuel, at amortized cost	402,328	389,662
Construction work in progress	320,167	3,294,641
Total electric plant	12,712,076	12,680,395
Investments and funds:		
Nuclear decommissioning trust fund	721,624	641,239
Investment in associated companies	86,720	82,133
Long-term investments	645,166	690,732
Other	38,862	35,585
Total investments and funds	1,492,372	1,449,689
Current assets:		
Cash and cash equivalents	337,813	490,592
Restricted cash and short-term investments	500	—
Short-term investments	124,572	143,931
Receivables	246,581	201,784
Inventories, at weighted average cost	356,285	337,045
Prepayments and other current assets	44,218	18,335
Total current assets	1,109,969	1,191,687
Deferred charges and other assets:		
Regulatory assets	1,103,633	1,131,489
Prepayments to Georgia Power Company	16,334	13,722
Other	43,154	57,869
Total deferred charges and other assets	1,163,121	1,203,080
Total assets	\$ 16,477,538	\$ 16,524,851
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	\$ 1,328,418	\$ 1,257,917
Long-term debt	12,134,194	11,600,917
Obligations under finance leases	33,173	43,586
Obligation under Rocky Mountain transactions	31,910	29,862
Other	5,715	5,152
Total capitalization	13,533,410	12,937,434
Current liabilities:		
Long-term debt and finance leases due within one year	398,979	384,426
Short-term borrowings	145,604	607,885
Accounts payable	138,537	117,272
Accrued interest	81,425	106,355
Member power bill prepayments, current	31,258	31,406
Other current liabilities	140,611	111,109
Total current liabilities	936,414	1,358,453
Deferred credits and other liabilities:		
Asset retirement obligations	1,279,121	1,458,937
Member power bill prepayments, non-current	54,183	47,133
Regulatory liabilities	661,592	706,320
Other	12,818	16,574
Total deferred credits and other liabilities	2,007,714	2,228,964
Total equity and liabilities	\$ 16,477,538	\$ 16,524,851
Commitments and Contingencies (Notes 1, 7, 10, 11 and 12)		

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF PATRONAGE CAPITAL AND MEMBERSHIP FEES
For the years ended December 31, 2024, 2023 and 2022

	(dollars in thousands)	
	2024	2023
Secured Long-term debt:		
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 1.03% to 8.21% (average rate of 3.48% at December 31, 2024) due in quarterly installments through 2048	\$ 2,796,291	\$ 2,663,385
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 1.44% to 4.01% (average rate of 2.94% at December 31, 2024) due in quarterly installments through 2044	4,050,644	4,177,967
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	437,500	500,000
• Series 2009B First Mortgage Bonds, 5.95%, due 2039	400,000	400,000
• Series 2009 Clean renewable energy bond, 1.81%, due 2024	—	1,010
• 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 2016A First Mortgage Bonds, 4.25% due 2046	250,000	250,000
• Series 2018A First Mortgage Bonds, 5.05% due 2048	500,000	500,000
• Series 2020A First Mortgage Bonds, 3.75% due 2050	450,000	450,000
• Series 2022A First Mortgage Bonds, 4.50% due 2047	500,000	500,000
• Series 2023A First Mortgage Bonds, 6.20% due 2053	400,000	400,000
• Series 2024A First Mortgage Bonds, 5.80% due 2054	350,000	—
First mortgage notes issued in connection with the sale of pollution control revenue bonds through the Development Authorities of Appling, Burke and Monroe Counties, Georgia:		
• Series 2013A Appling, Burke and Monroe Term rate bonds, 1.50% through February 3, 2025, due 2038 through 2040	212,760	212,760
• Series 2017A, B Burke Indexed put bonds—weekly reset, 4.57% due 2045	91,645	91,645
• Series 2017C, D Burke Fixed rate bonds, 4.125%, due 2041 through 2045	200,000	200,000
• Series 2017E Burke Term rate bonds, 3.25% through February 3, 2025, due 2041 through 2045	100,000	100,000
• Series 2017F Burke Indexed put bonds—weekly reset, 4.82% due 2040 through 2045	99,785	99,785
Total Secured Long-term debt	\$ 12,388,625	\$ 12,096,552
Unsecured debt:		
Commercial paper refinanced on a long-term basis	254,463	—
Total Long-term debt	\$ 12,643,088	\$ 12,096,552
Obligations under finance leases	43,586	52,937
Obligation under Rocky Mountain transactions	31,910	29,862
Other	5,715	5,152
Patronage capital and membership fees	1,328,418	1,257,917
Subtotal	\$ 14,052,717	\$ 13,442,420
Less: long-term debt and finance leases due within one year	(398,979)	(384,426)
Less: unamortized debt issuance costs	(97,623)	(97,850)
Less: unamortized bond discounts on long-term debt	(22,705)	(22,710)
Total capitalization	\$ 13,533,410	\$ 12,937,434

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, 2024, 2023 and 2022

	(dollars in thousands)		
	2024	2023	2022
Cash flows from operating activities:			
Net margin	\$ 70,501	\$ 65,790	\$ 61,704
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	\$ 569,349	\$ 441,926	\$ 451,899
Accretion cost	69,223	65,907	55,953
Amortization of deferred gains	(1,789)	(1,789)	(1,789)
Allowance for equity funds used during construction	(1,756)	(750)	(700)
Deferred outage costs	(46,065)	(32,390)	(30,926)
(Gain) loss on sale of investments	(90,356)	(6,954)	21,950
Regulatory deferral of costs associated with nuclear decommissioning	74,805	(21,449)	(54,529)
Other	(47,605)	(5,150)	(712)
Change in operating assets and liabilities:			
Receivables	(32,222)	12,011	(68,550)
Inventories	(34,717)	(38,562)	(36,235)
Prepayments and other current assets	(7,912)	(2,211)	25,031
Accounts payable	29,156	(104,164)	7,008
Accrued interest	(24,930)	903	9,042
Accrued taxes	9,678	1,087	52,764
Other current liabilities	13,485	(65,795)	32,300
Rate management program (billing credits applied) collections, net	(126,876)	(56,612)	19,847
Other	6,902	(57,281)	2,217
Total adjustments	\$ 358,370	\$ 128,727	\$ 484,570
Net cash provided by operating activities	\$ 428,871	\$ 194,517	\$ 546,274
Cash flows from investing activities:			
Property additions	\$ (662,122)	\$ (474,952)	\$ (1,156,383)
Plant acquisition	(75,240)	(16,743)	(86,826)
Litigation proceeds received for capitalized spent nuclear fuel storage costs	14,347	—	—
Activity in nuclear decommissioning trust fund – Purchases	(1,149,281)	(535,027)	(204,500)
Activity in nuclear decommissioning trust fund – Proceeds	1,129,631	520,986	194,046
Decrease in restricted investments	—	74,031	246,022
Activity in other long-term investments – Purchases	(264,277)	(262,712)	(185,092)
Activity in other long-term investments – Proceeds	354,894	199,200	107,082
Other	1,156	13,782	4,040
Net cash used in investing activities	\$ (650,892)	\$ (481,435)	\$ (1,081,611)
Cash flows from financing activities:			
Long-term debt proceeds	\$ 667,493	\$ 506,272	\$ 1,414,925
Long-term debt payments	(384,771)	(358,477)	(397,162)
Decrease in short-term borrowings, net	(207,818)	(47,765)	(440,321)
Other	(5,162)	51,699	2,526
Net cash provided by financing activities	69,742	151,729	579,968
Net (decrease) increase in cash, cash equivalents and restricted cash	\$ (152,279)	\$ (135,189)	\$ 44,631
Cash, cash equivalents and restricted cash at beginning of period	490,592	625,781	581,150
Cash, cash equivalents and restricted cash at end of period	\$ 338,313	\$ 490,592	\$ 625,781
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	\$ 492,055	\$ 278,952	\$ 182,066
Supplemental disclosure of non-cash investing and financing activities:			
Change in asset retirement obligations	\$ (225,604)	\$ 63,803	\$ 10,486
Accrued property additions at end of period	\$ 49,683	\$ 39,854	\$ 79,204

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF PATRONAGE CAPITAL AND MEMBERSHIP FEES
For the years ended December 31, 2024, 2023 and 2022

	(dollars in thousands)
Balance at December 31, 2021	\$ 1,130,423
Components of comprehensive margin in 2022:	
Net margin	61,704
Balance at December 31, 2022	<u>\$ 1,192,127</u>
Components of comprehensive margin in 2023:	
Net margin	65,790
Balance at December 31, 2023	<u>\$ 1,257,917</u>
Components of comprehensive margin in 2024:	
Net margin	70,501
Balance at December 31, 2024	<u>\$ 1,328,418</u>

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2024, 2023 and 2022

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 8,594 megawatts of summer planning reserve capacity. We also manage and operate Smarr EMC which owns 729 megawatts of summer planning reserve capacity. In addition, we supply financial and management services to Green Power EMC, which purchases energy from renewable energy facilities totaling 820 megawatts of capacity, including 804 megawatts sourced by solar energy. Georgia Power Company is a co-owner and the operating agent of our nuclear and coal-fired generating units.

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, 2024 and 2023 and the reported amounts of revenues and expenses for each of the three years in the period ended December 31, 2024. Examples of estimates used include items related to our asset retirement obligations. Accounting for asset retirement 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. 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 resources.

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. 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 2024, 2023 and 2022, we achieved a margins for interest ratio of 1.14.

e. Revenue recognition

As an electric membership cooperative, our principal business is providing wholesale electric service to our members. Our operating revenues are derived primarily from wholesale power contracts we have with each of our 38 members. These contracts, which extend to December 31, 2085, are substantially identical and obligate our members jointly and severally to pay all expenses associated with owning and operating our power supply business. As a cooperative, 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 also sell energy and capacity to non-members through industry standard contracts and negotiated agreements, respectively. We do not have multiple operating segments.

Pursuant to our contracts, we primarily provide two services, capacity and energy. Capacity and energy revenues are recognized by us upon transfer of control of promised services to our members and non-members in an amount that reflects the consideration we expect to receive in exchange for those services. Capacity and energy are distinct and we account for them as separate performance obligations. The obligations to provide capacity and energy are satisfied over time as the customer simultaneously receives and consumes the benefit of these services. Both performance obligations are provided directly by us and not through a third party.

Each of our members is obligated 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. Revenues from our members are derived through a cost-plus rate structure which is set forth as a formula in the rate schedule to the wholesale power contracts. The formulary rate provides for the pass-through of our (i) fixed costs (net of any income from other sources) plus a targeted margin as capacity revenues and (ii) variable costs as energy revenues from our members. Power purchase and sale agreements between us and non-members obligate each non-member to pay us for capacity, if any, and energy furnished in accordance with the prices mutually agreed upon. Margins produced from non-member sales are included in our rate schedule formula and reduce revenue requirements from our members. As of December 31, 2024 and 2023, we did not have any significant long-term contracts with non-members.

The consideration we receive for providing capacity services to our members is determined by our formulary rate on an annual basis. The components of the formulary rate associated with capacity costs include the annual budget of fixed costs, a targeted margin and income from other sources. Capacity revenues, therefore, vary to the extent these components vary. Fixed costs include items such as fixed operation and maintenance expenses, administrative and general expenses, depreciation and interest. Year to year, capacity revenue fluctuations are generally due to the recovery of fixed operation and maintenance expenses. Fixed costs also include certain costs, such as major maintenance costs, which will be recognized as expense in future periods. Recognition of revenues associated with these future expenses is deferred pursuant to Accounting Standards Codification (ASC) 980, Regulated Operations. The regulatory liabilities are amortized to revenue in accordance with the associated revenue deferral plan as the expenses are recognized. For information regarding regulatory accounting, see Note 1q.

Capacity revenues are recognized by us for standing ready to deliver electricity to our customers. Our member capacity revenues are based on the associated costs we expect to recover in a given year and are recognized and billed to our members in equal monthly installments over the course of the year regardless of whether our generation and purchased power resources are dispatched to produce electricity. Non-member capacity revenues are billed and recognized in accordance with the terms of the associated contract.

We have a power bill prepayment program pursuant to which our members may prepay future capacity costs and receive a discount. As this program provides us with financing, we adjust our capacity revenues by the amount of the discount, which is based on our avoided cost of borrowing. For additional information regarding our member prepayment program, see Note 1p.

We satisfy our performance obligations to deliver energy as energy is delivered to the applicable meter points. We determine the standard selling price for energy we deliver to our members based upon the variable costs incurred to generate or purchase that energy. Fuel expense is the primary variable cost. Energy revenue recognized equals the actual variable expenses incurred in any given accounting period. Our member energy revenues fluctuate from period to period based on several factors, including fuel costs, weather and other seasonal factors, load requirements in our members' service territories, variable operating costs, the 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. The standard selling price for our energy revenues from non-members is the price mutually agreed upon.

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 2024, 2023 and 2022, our board approved, and we achieved, a targeted margins for interest ratio of 1.14. For 2025, our board of directors approved a budget to achieve a 1.10 margins for interest ratio. Historically, our board of directors has approved adjustments to revenue requirements by year end such that revenue in excess of that required to meet the targeted margins for interest ratio is refunded to the members. Given that our capacity revenues are based upon budgeted expenditures and generally recognized and billed to our members in equal monthly installments over the course of the year, we may recognize capacity revenues that exceed our actual fixed costs and targeted margins in any given interim reporting period. At each interim reporting period we assess our projected revenue requirements through year end to determine whether a refund to our members of excess consideration is likely. If so, we reduce our capacity revenues and recognize a refund liability to our members. Refund liabilities, if any, are included in accounts payable on our consolidated balance sheets. As of December 31, 2024 and December 31, 2023, we recognized refund liabilities totaling \$55,914,000 and \$34,266,000, respectively. Based on our current agreements with non-members, we do not refund any consideration received from non-members.

Sales to members were as follows:

	(dollars in thousands)		
	2024	2023	2022
Capacity revenues	\$ 1,501,903	\$ 1,082,368	\$ 984,036
Energy revenues	643,619	599,198	990,647
Total	<u>\$ 2,145,522</u>	<u>\$ 1,681,566</u>	<u>\$ 1,974,683</u>

In 2024, we recorded a reduction of \$34,400,000 in fuel expense and a corresponding decrease in member energy revenues for the settlement of two claims related to spent nuclear fuel storage costs. The combined settlements were credited to fuel expense, electric plant in service and production expenses, the accounts to which the original costs were recorded. For additional information regarding the claims for spent nuclear fuel storage costs, see Note 1g.

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2024, 2023 or 2022:

	2024	2023	2022
Jackson EMC	18.0 %	15.1 %	16.0 %
Cobb EMC	9.0 %	11.4 %	9.5 %
GreyStone Power Corporation, an EMC	9.3 %	8.5 %	10.0 %

Energy revenues from non-members were primarily from the sale of the BC Smith deferring members' output into the wholesale market. In 2024, 2023 and 2022, we recognized capacity revenues from non-members related to a tolling agreement associated with the two units we acquired at the Washington County Power Plant in 2022. This tolling agreement with Georgia Power expired in May 2024.

Sales to non-members were as follows:

	(dollars in thousands)		
	2024	2023	2022
Energy revenues	\$ 34,753	\$ 44,995	\$ 155,372
Capacity revenues	1,572	13,624	82
Total	\$ 36,325	\$ 58,619	\$ 155,454

Electric capacity and energy revenues are recognized by us without any obligation for returns, warranties or taxes collected. As our members are jointly and severally obligated to pay all expenses associated with owning and operating our power supply business and we perform an on-going assessment of the credit worthiness of non-members and have not had a history of any write-offs from non-members, we have not recorded an allowance for doubtful accounts associated with our receivables from members or non-members.

We have a rate management program that ended in December 2023, which allowed us to expense and recover interest costs associated with the construction of Vogtle Units No. 3 and No. 4, on a current basis, that would otherwise be deferred or capitalized. Under this program, amounts billed to participating members in 2023 and 2022 were \$9,261,000 and \$14,796,000, respectively. The cumulative amount billed since inception of the program totaled \$135,693,000.

In 2018, we began an additional rate management program that allowed us to recover future expense on a current basis from our members. In general, the program allowed for additional collections over a five-year period with those amounts then applied to billings over the subsequent five-year period. The program is designed primarily as a mechanism to assist our members in managing the rate impacts associated with the commercial operation of the new Vogtle units. During the first quarter of 2022, we began applying billing credits to some of our participating members within this program. In December 2022, collections from our members ended for this rate management program. Under this program, net billing credits and amounts billed to participating members during 2024, 2023 and 2022 were (\$121,638,000), (52,378,000) and \$11,774,000 respectively. Funds collected through this program are invested and held until applied to members' bills. Investments that mature and are expected to be applied to members' bills within the next twelve months are included in the Short-term investments line item within our consolidated balance sheets. In conjunction with this program, we are applying regulated operations accounting to defer these revenues and related investment income on the funds collected. Amounts deferred under the program will be amortized to income when applied to members' bills. The net cumulative amount billed since inception of the program totaled \$369,102,000. As of December 31, 2024, \$197,373,000 is our remaining liability to be credited to our members' bills. For additional information regarding our revenue deferral plan, see Note 1q.

f. Receivables

A substantial portion of our receivables are related to capacity and energy 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. Receivables from contracts with our members at December 31, 2024, 2023 and 2022 were \$177,790,000, \$170,901,000 and \$187,401,000, respectively. Payment is typically received the following month in which capacity and energy are billed. Estimated energy charges are billed based on the amount of energy supplied during the month and are adjusted when actual costs are available, generally the following month.

The remainder of our receivables is primarily related to transactions with non-members from nuclear storage litigation judgments, the sale of the BC Smith deferring members' output, affiliated companies and investment income. Our receivables from non-members at December 31, 2024, 2023 and 2022 were \$68,791,000 and \$30,883,000, and \$32,614,000, respectively.

As a result of our historical experience, the short duration lifetime of our receivables and the short time horizon over which to consider expectations of future economic conditions, we have assessed that non-collection of the cost basis of our receivables is remote. During 2024, 2023 and 2022, no credit losses were recognized on any receivables that arose from contracts with members or non-members.

g. Nuclear fuel cost

The cost of nuclear fuel is amortized to fuel expense based on usage. The total nuclear fuel expense for 2024, 2023 and 2022 amounted to \$81,425,000, \$84,192,000, and \$73,871,000, 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. Damages will continue to accumulate until the issue is resolved, the U.S. government disposes of Georgia Power's spent nuclear fuel pursuant to its contractual obligations, or alternative storage is otherwise provided.

Georgia Power filed multiple claims against the U.S. government seeking damages for spent nuclear fuel storage costs at Plant Hatch and Plant Vogtle Units No. 1 and No. 2 covering the period from January 1, 2011 through December 31, 2019.

In June 2024, the U.S. Court of Federal Claims entered a final judgment awarding damages to Georgia Power for spent nuclear fuel storage costs incurred at Plants Hatch and Vogtle from January 1, 2011 through December 31, 2014. Our share of the judgements is approximately \$39,400,000. During the third quarter of 2024, we recorded a settlement receivable of approximately \$39,400,000 in our consolidated financial statements.

In August 2024, the U.S. Court of Federal Claims entered a final judgment awarding damages to Georgia Power for spent nuclear fuel storage costs incurred at Plants Hatch and Vogtle from January 1, 2015 through December 31, 2019. Our share of the judgements is approximately \$38,900,000. During the third quarter of 2024, we recorded a settlement receivable of approximately \$38,900,000 in our consolidated financial statements.

The combined receivables totaled \$78,300,000 and credits were recorded to the accounts to which the original costs were recorded. We credited fuel expense by \$34,400,000, electric plant in service by \$36,000,000 and production expenses by \$7,900,000. As of December 31, 2024, \$39,433,000 was outstanding for both receivables and included in the Receivables line items within our consolidated balance sheets.

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

h. 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 and coal ash ponds. In addition, we have asset retirement obligations related to gypsum cells, powder activated carbon cells, landfill sites, asbestos removal and nuclear interim costs. 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 coal-fired 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 2024.

The following table reflects the details of the asset retirement obligations included in the consolidated balance sheets for the years 2024 and 2023.

	(dollars in thousands)			
	Nuclear	Coal Ash Pond	Other	Total
Balance at December 31, 2023	\$ 929,804	\$ 463,967	\$ 65,166	\$ 1,458,937
Liabilities incurred	65,149	—	—	65,149
Liabilities settled	—	(21,593)	(1,700)	(23,293)
Accretion	49,307	17,109	2,807	69,223
Deferred accretion	—	(142)	—	(142)
Change in cash flow estimates	(232,021)	(56,171)	(2,561)	(290,753)
Balance at December 31, 2024	\$ 812,239	\$ 403,170	\$ 63,712	\$ 1,279,121

	(dollars in thousands)			
	Nuclear	Coal Ash Pond	Other	Total
Balance at December 31, 2022	\$ 820,106	\$ 461,528	\$ 62,109	\$ 1,343,743
Liabilities incurred	62,841	—	—	62,841
Liabilities settled	—	(14,445)	(76)	(14,521)
Accretion	46,857	16,558	2,492	65,907
Deferred accretion	—	5	—	5
Change in cash flow estimates	—	321	641	962
Balance at December 31, 2023	\$ 929,804	\$ 463,967	\$ 65,166	\$ 1,458,937

Asset Retirement Obligations

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, and how costs will escalate with inflation. During the third quarter of 2024, we performed a revised assessment of our nuclear decommissioning asset retirement obligations for Plants Hatch and Vogtle. Based on the revised studies of estimates computed by third party specialists in the nuclear regulatory environment, we recorded a decrease of approximately \$232,000,000 in asset retirement obligations and a corresponding decrease in asset retirement costs (electric plant in service). The decrease was primarily due to extending the assumed decommissioning dates of the reactors and an increase in credit-adjusted risk-free rates, partially offset by an increase in base year decommissioning costs. While evaluating the probability of the assumed dates of decommissioning, factors considered included, but were not limited to, examination of the nuclear unit's remaining operating and economic life, re-licensing expectations, and industry trends. Ultimately, the revised cost site studies reflected later assumed dates of decommissioning than the prior studies.

In March 2023 and February 2024, Plant Vogtle Units No. 3's and No. 4's nuclear reactors achieved self-sustaining nuclear fission, commonly referred to as initial criticality. As a result, in March 2023, we recognized a new nuclear asset retirement obligation for Plant Vogtle Unit No. 3 totaling \$62,841,000. During the first quarter of 2024, we recognized a new nuclear asset retirement obligation totaling \$65,100,000 for Plant Vogtle Unit No. 4. Our

portion of the estimated costs of decommissioning co-owned nuclear facilities for which we have recorded asset retirement obligations as of December 31, 2024 are as follows:

2024 site study	(dollars in thousands)			
	Hatch Unit No. 1	Hatch Unit No. 2	Vogtle Unit No. 1	Vogtle Unit No. 2
Estimated costs based on site study in 2024 dollars:				
Radiated structures	\$ 234,000	\$ 242,000	\$ 216,000	\$ 226,000
Spent fuel management	95,000	89,000	86,000	82,000
Non-radiated structures	19,000	27,000	31,000	39,000
Total estimated site study costs	<u>\$ 348,000</u>	<u>\$ 358,000</u>	<u>\$ 333,000</u>	<u>\$ 347,000</u>

2024 site study	(dollars in thousands)	
	Vogtle Unit No. 3	Vogtle Unit No. 4
Estimated costs based on site study in 2024 dollars:		
Radiated structures	\$ 195,000	\$ 199,000
Spent fuel management	27,000	29,000
Non-radiated structures	25,000	33,000
Total estimated site study costs	<u>\$ 247,000</u>	<u>\$ 261,000</u>

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

We apply the provision of regulated operations to nuclear decommissioning transactions such that collections and investment income (interest, dividends and realized gains and losses) of our nuclear decommissioning funds are compared to the associated decommissioning expenses with the difference deferred as regulatory asset or liability. As this difference is largely attributable to the timing of decommissioning fund earnings, the difference is recorded as an adjustment to investment income in our consolidated statements of revenues and expenses. Unrealized gains and losses of the decommissioning funds are recorded directly to the regulatory asset or liability for asset retirement obligations in accordance with our ratemaking treatment.

Coal Combustion Residuals. Coal combustion residuals (CCR) are subject to federal and state regulations. Our obligations associated with CCR are primarily for the closure of coal ash ponds. During 2024 and 2023, assessments of the coal ash pond asset retirement obligation resulted in a \$56,171,000 decrease and a \$321,000 increase in cash flow estimates for coal ash decommissioning, respectively. These adjustments to the asset retirement obligations had a corresponding offset to our coal ash related regulatory asset. The 2024 decrease was primarily due to a reduction of estimated base closure and post-closure costs, partially offset by an increase in water treatment costs required under new effluent limitations guidelines (ELG) and CCR rules. The 2024 ELG Supplemental Rule included additional treatment requirements for CCR and non-CCR waste streams once a site is retired. 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 regulations. Additional adjustments to the asset retirement obligations are expected periodically due to potential changes in estimates and assumptions.

We have internally segregated the funds collected for coal ash pond and other CCR decommissioning costs, including earnings thereon. As of December 31, 2024 and December 31, 2023, the fund balances were \$201,535,000 and \$176,630,000, respectively, and included in the Long-term investments line items within our consolidated balance sheets.

We apply the provision of regulated operations to coal ash pond and other CCR decommissioning transactions such that collections and investment income (interest, dividends and realized gains and losses) are compared to the associated decommissioning expenses with the difference deferred to or amortized from the regulatory asset. This

difference is recorded to the associated expenses in our consolidated statements of revenues and expenses. Unrealized gains and losses of the associated decommissioning fund are recorded directly to the regulatory asset in accordance with our ratemaking treatment.

Other Retirement Costs

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 1q.

i. 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. As a result of nuclear fuel load for Plant Vogtle Units No. 3 and No. 4, in 2024 and 2023, we contributed \$8,632,000 and \$4,619,000, respectively, 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 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 sheets. We contributed \$8,333,000 and \$10,000,000 into the internal funds in 2024 and 2023, respectively.

The following table outlines the fair value of our nuclear decommissioning funds as of December 31, 2024 and December 31, 2023. The funds were invested in a diversified mix of approximately 51% equity, 34% fixed income securities and 15% temporarily in cash pending reallocation between equity funds in 2024 and 71% equity and 29% fixed income securities in 2023.

<i>External Trust Funds:</i>	2024				
	(dollars in thousands)				
	Cost 12/31/2023	Purchases	Net Proceeds⁽¹⁾	Unrealized Gain(Loss)	Fair Value 12/31/2024
Equity	\$ 249,063	\$ 169,927	\$ (75,461)	\$ 186,129	\$ 529,658
Debt	195,756	788,109	(781,509)	(8,713)	193,643
Other	(729)	191,247	(192,195)	—	(1,677)
	<u>\$ 444,090</u>	<u>\$ 1,149,283</u>	<u>\$ (1,049,165)</u>	<u>\$ 177,416</u>	<u>\$ 721,624</u>

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of \$100,118,000.

2024					
<i>Internal Funds:</i>	(dollars in thousands)				
	Cost 12/31/2023	Purchases	Net Proceeds ⁽¹⁾	Unrealized Gain(Loss)	Fair Value 12/31/2024
Equity	\$ 86,378	\$ —	\$ 3,257	\$ 40,466	\$ 130,101
Debt	49,320	139,657	(116,098)	(2,180)	70,699
	<u>\$ 135,698</u>	<u>\$ 139,657</u>	<u>\$ (112,841)</u>	<u>\$ 38,286</u>	<u>\$ 200,800</u>

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of \$26,817,000.

2023					
<i>External Trust Funds:</i>	(dollars in thousands)				
	Cost 12/31/2022	Purchases	Net Proceeds ⁽¹⁾	Unrealized Gain(Loss)	Fair Value 12/31/2023
Equity	\$ 228,936	\$ 29,307	\$ (9,180)	\$ 201,900	\$ 450,963
Debt	192,986	485,705	(482,935)	(4,751)	191,005
Other	91	20,015	(20,835)	—	(729)
	<u>\$ 422,013</u>	<u>\$ 535,027</u>	<u>\$ (512,950)</u>	<u>\$ 197,149</u>	<u>\$ 641,239</u>

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends and fees of \$22,078,000.

2023					
<i>Internal Funds:</i>	(dollars in thousands)				
	Cost 12/31/2022	Purchases	Net Proceeds ⁽¹⁾	Unrealized Gain(Loss)	Fair Value 12/31/2023
Equity	\$ 79,122	\$ —	\$ 7,256	\$ 39,134	\$ 125,512
Debt	43,032	59,630	(53,342)	(942)	48,378
	<u>\$ 122,154</u>	<u>\$ 59,630</u>	<u>\$ (46,086)</u>	<u>\$ 38,192</u>	<u>\$ 173,890</u>

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of \$13,542,000.

Realized and unrealized gains and losses of the nuclear decommissioning funds that would be recorded in earnings 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.

j. Depreciation

Depreciation is computed on additions when they are placed in service using the composite straight-line method. We use prescribed depreciation rates as well as site specific rates determined through depreciation studies as approved by the Rural Utilities Service. The depreciation rates for steam, nuclear and other production in the table below reflect revised rates from depreciation rate studies completed in 2020 or 2024. Site specific depreciation

studies are performed every five years. Annual weighted average depreciation rates in effect in 2024, 2023, and 2022 were as follows:

	Remaining Useful Life Range in years*	2024	2023	2022
Steam production	18-20	3.04 %	3.05 %	13.77 %
Nuclear production	10-59	1.88 %	1.87 %	2.17 %
Hydro production	42	2.00 %	2.00 %	2.00 %
Other production	15-29	2.71 %	2.73 %	2.68 %
Transmission	10-59	2.75 %	2.75 %	2.75 %
General	1-41	2.00-33.33%	2.00-33.33%	2.00-33.33%

* Based on estimated retirement dates as of 2024. Actual retirement dates may be different.

Depreciation expense for the years 2024, 2023 and 2022 was \$404,178,000, \$321,047,000, and \$278,452,000, respectively. In 2024, depreciation expense increased by \$83,131,000 compared to 2023 primarily due to Plant Vogtle Unit No. 4 achieving commercial operation in April 2024 and a full year of operating Plant Vogtle Unit No. 3. In 2023, depreciation expense increased by \$42,595,000 compared to 2022 primarily due to Plant Vogtle Unit No. 3 achieving commercial operation in July 2023. In 2021, the composite depreciation rate for Plant Wansley was increased in anticipation of the plant's retirement in 2022. In addition to the depreciation expense recognized in 2022 and 2021, \$165,013,000 and \$204,891,000, respectively, of Plant Wansley's depreciation expense was deferred. Subsequent to the retirement of Plant Wansley, we amortized approximately \$20,603,000 and \$25,900,000 of deferred depreciation expense in 2024 and 2023, respectively. In 2024, we recorded an increase of approximately \$21,900,000 of deferred expense relating to additional dismantlement costs for Plant Wansley. See Note 1q for information regarding regulatory assets and liabilities.

k. 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 2024, 2023 and 2022, the allowance for funds used during construction rates were 4.29%, 4.18% and 4.03%, 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 is charged to the accumulated provision for depreciation. Cost of removal, less salvage, is charged to a regulatory liability, accumulated retirement costs for other assets. 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.

l. 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.

m. Restricted cash and short-term investments

Restricted cash consists of collateral posted by our counterparties under our natural gas swap agreements. The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the

consolidated balance sheets that sum to the total of the same such amounts reported in the consolidated statements of cash flows.

Classification

	Twelve months ended	
	December 31, 2024	December 31, 2023
	(dollars in thousands)	
Cash and cash equivalents	\$ 337,813	\$ 490,592
Restricted cash included in restricted cash and short-term investments	500	—
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	\$ 338,313	\$ 490,592

n. 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. 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, 2024 and December 31, 2023, fossil fuels inventories were \$83,705,000 and \$74,149,000, respectively. Inventories for spare parts at 2024 and 2023 were \$272,580,000 and \$262,896,000, respectively.

o. Deferred charges and other assets

Deferred charges and other assets represent regulatory assets, long-term prepayments to Georgia Power Company and other deferred charges. For a discussion regarding regulatory assets, see Note 1q. Other deferred charges primarily represent the fair value of our natural gas contracts that will settle after the next twelve months and other long-term prepayments.

p. 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 December 2028, with the majority of the balance scheduled to be credited by the end of 2026.

Deferred credits and other liabilities also consists of asset retirement obligations as discussed in Note 1h and regulatory liabilities in Note 1q.

q. 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 established under the wholesale power contracts we have with each of our members. These contracts extend through December 31, 2085. 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)	
	2024	2023
<i>Regulatory Assets:</i>		
Premium and loss on reacquired debt ^(a)	\$ 21,587	\$ 25,476
Amortization on financing leases ^(b)	24,699	28,780
Outage costs ^(c)	45,749	30,040
Asset retirement obligations – Ashpond and other ^(l)	268,074	343,523
Depreciation expense - Plant Vogtle ^(d)	32,702	34,125
Depreciation expense - Plant Wansley ^(e)	337,181	335,884
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs ^(f)	54,545	55,159
Interest rate options cost ^(g)	130,456	137,463
Deferral of effects on net margin – TA Smith Energy Facility ^(h)	124,840	130,786
Deferral of effects on net margin – BC Smith Energy Facility ^(p)	27,841	—
Inventory adjustments - TA Smith Energy Facility ^(q)	14,723	—
Other regulatory assets ^(o)	21,236	10,253
<i>Total Regulatory Assets</i>	\$ 1,103,633	\$ 1,131,489
<i>Regulatory Liabilities:</i>		
Accumulated retirement costs for other obligations ⁽ⁱ⁾	\$ 29,975	\$ 25,992
Deferral of effects on net margin – Hawk Road Energy Facility ^(h)	15,404	16,020
Deferral of effects on net margin – BC Smith Energy Facility ^(p)	—	546
Major maintenance reserve ^(j)	99,987	120,547
Amortization on financing leases ^(b)	—	2,658
Deferred debt service adder ^(k)	186,757	170,466
Asset retirement obligations – Nuclear ^(l)	102,858	47,217
Revenue deferral plan ^(m)	197,373	308,507
Natural gas hedges ⁽ⁿ⁾	28,624	13,445
Other regulatory liabilities ^(o)	614	922
<i>Total Regulatory Liabilities</i>	\$ 661,592	\$ 706,320
Net regulatory assets	\$ 442,041	\$ 425,169

(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 19 years.

(b) Represents the difference between expense recognized for rate-making purposes versus financial statement purposes related to finance 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 periods up to 60 months, depending on the operating cycle of each unit. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 or 24-month operating cycles of each unit.

(d) 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.

(e) Represents the deferral of accelerated depreciation associated with the early retirement of Plant Wansley, which occurred on August 31, 2022. Amortization commenced upon the retirement of Plant Wansley and will end no later than December 31, 2040.

(f) Deferred charges consist of training related costs, including interest and 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 premiums paid to purchase interest rate options used to hedge interest rates on certain borrowings, related carrying costs and other incidentals associated with construction of Vogtle Units No. 3 and No. 4. Amortization commenced in August 2023 after Vogtle Unit No. 3 was placed in service on July 31, 2023.

(h) Effects on net margin for TA 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 the difference in the timing of recognition of decommissioning costs for financial statement purposes versus ratemaking purposes, as well as the deferral of unrealized gains and losses of funds set aside for decommissioning.
- (m) Deferred revenues under a rate management program that allowed for additional collections over a five-year period beginning in 2018. These amounts are being amortized to income and applied to member billings, per each member's election, over the subsequent five-year period.
- (n) Represents the deferral of unrealized gains on natural gas contracts.
- (o) The amortization periods for other regulatory assets range up to 29 years and the amortization periods of other regulatory liabilities range up to 2 years.
- (p) Effects on net margin for the BC Smith Energy Facility that are being deferred until on or before January 2026 and will be amortized over the remaining life of the plant.
- (q) Represents the write-down of inventory associated with the TA Smith acquisition. Amortization commenced on June 1, 2024 and will end no later than May 31, 2039.

r. 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 owned facilities. For 2024, 2023, and 2022, we incurred expenses from Georgia Transmission of \$43,965,000, \$41,426,000, and \$40,774,000, respectively.

We, Georgia Transmission and 38 of our members are members of Georgia System Operations. Georgia System Operations operates the system control center and currently provides us system operations services and administrative support services. For 2024, 2023, and 2022, we incurred expenses from Georgia System Operations of \$32,932,000, \$30,109,000, and \$27,416,000, respectively.

s. Other income

Other income includes net revenue from Georgia Transmission and Georgia System Operations for administrative costs, as well as capital credits from investments in associated organizations and other miscellaneous income.

t. Recently issued or adopted accounting pronouncements

In November 2023, the Financial Accounting Standards Board (FASB) issued "Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures." The amendments in this update are intended to improve reportable segment disclosure requirements, primarily through enhanced disclosures about significant expenses. The amendments in this update require disclosures to include significant segment expenses that are regularly provided to the chief operating decision maker (CODM), a description of other segment items by reportable segment, and any additional measures of a segment's profit or loss used by the CODM when deciding how to allocate resources. The amendments in this update are also applicable to entities with only one reportable segment. The amendments in this update also require all annual disclosures currently required by Topic 280 to be included in interim periods. The new standard is effective for us for annual reporting periods beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted and requires retrospective application to all prior periods presented in the financial statements.

We have fully completed our evaluation of this new standard. The adoption of this standard on December 31, 2024 did not have a material impact on our consolidated financial statements. For the related segment reporting disclosure, see Note 15.

In December 2023, the FASB amended "Income Taxes (Topic 740): Improvements to Income Tax Disclosures". The amendments in this update requires additional disclosures related to the rate reconciliation, income taxes paid and other amendments intended to improve effectiveness and comparability. The amendments in this update are effective for us for annual periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis. Retrospective application is permitted. We are currently evaluating the future impact of this standard on our consolidated financial statements, however, we do not anticipate the impact will be significant.

In November 2024, the FASB issued "Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosure (Subtopic 220-40): Disaggregation of Income Statement Expenses", which requires the disaggregation of certain expenses in the notes to the financial statements, to provide enhanced transparency into the expense captions presented on the face of the income statement. The new standard is effective for us for annual reporting periods beginning after December 15, 2026 and interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted and the new standard may be applied either prospectively or retrospectively. We are currently evaluating the impact of this standard on our consolidated financial statements.

u. Measurement of credit losses on financial instruments

The financial assets we hold that are subject to credit losses (Topic 326) are predominately accounts receivable and certain cash equivalents classified as held-to-maturity debt (e.g. commercial paper). Our receivables are generally due within thirty days or less with a significant portion related to billings to our members. See Note 1f for information regarding our member receivables. Commercial paper we invest in is rated as investment grade. Given our historical experience, the short duration lifetime of these financial assets and the short time horizon over which to consider expectations of future economic conditions, we have assessed that non-collection of the cost basis of these financial assets is remote and we have not recognized an allowance for credit losses.

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, 2024	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	\$ 245,313	\$ 245,313	\$ —	\$ —	
Corporate bonds and debt	\$ 82,316	—	82,309	7	
US Treasury securities	\$ 53,806	53,806	—	—	
Mortgage backed securities	\$ 70,193	—	70,193	—	
Domestic mutual funds	\$ 95,175	95,175	—	—	
Municipal bonds	\$ 3,375	—	3,375	—	
Federal agency securities	\$ 8,487	—	8,487	—	
Non-US Gov't bonds & private placements	\$ 3,319	—	3,319	—	
International mutual funds	\$ 4,228	—	4,228	—	
Money market	\$ 138,553	138,553	—	—	
Other	\$ 16,859	16,859	—	—	
Long-term investments:					
Corporate bonds and debt	\$ 20,972	—	20,972	—	
US Treasury securities	\$ 25,654	25,654	—	—	
Mortgage backed securities	\$ 20,232	—	20,232	—	
Domestic mutual funds	\$ 394,595	394,595	—	—	
Treasury STRIPS	\$ 142,199	—	142,199	—	
Non-US Gov't bonds & private placements	\$ 1,805	—	1,805	—	
International mutual funds	\$ 39,340	—	39,340	—	
Other	\$ 369	369	—	—	
Short-term investments: Treasury STRIPS	\$ 124,572	—	124,572	—	
Natural gas swaps	\$ 28,624	—	28,624	—	

Fair Value Measurements at Reporting Date Using				
December 31, 2023	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	\$ 234,979	\$ 234,979	\$ —	\$ —
International equity trust	\$ 134,911	—	134,911	\$ —
Corporate bonds and debt	\$ 67,986	—	67,900	86
US Treasury securities	\$ 43,917	43,917	—	—
Mortgage backed securities	\$ 58,763	—	58,763	—
Domestic mutual funds	\$ 85,481	85,481	—	—
Municipal Bonds	\$ 303	—	303	—
Federal agency securities	\$ 7,256	—	7,256	—
Non-US Gov't bonds & private placements	\$ 2,717	—	2,717	—
International mutual funds	\$ 2,012	—	2,012	—
Other	\$ 2,914	2,914	—	—
Long-term investments:				
International equity trust	\$ 43,202	—	43,202	—
Corporate bonds and debt	\$ 14,151	—	14,151	—
US Treasury securities	\$ 17,243	17,243	—	—
Mortgage backed securities	\$ 15,024	—	15,024	—
Domestic mutual funds	\$ 378,387	378,387	—	—
Treasury STRIPS	\$ 220,765	—	220,765	—
Non-US Gov't bonds & private placements	\$ 1,568	—	1,568	—
Other	\$ 392	392	—	—
Short-term investments: Treasury STRIPS	\$ 143,931	—	143,931	—
Natural gas swaps	\$ 13,445	—	13,445	—

The Level 2 investments above in corporate bonds and debt, federal agency mortgage backed securities, and mortgage 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 3-day redemption notice period.

The Level 3 investments above in corporate bonds and debt consist of investments in bank loans which are not exchange traded. Although these securities may be liquid and priced daily, their inputs are not observable.

The estimated fair values of our long-term debt, including current maturities at December 31, 2024 and 2023 were as follows:

	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
(in thousands)				
Long-term debt	\$ 12,643,088	\$ 10,666,727	\$ 12,096,552	\$ 10,638,749

The estimated fair value of long-term debt is classified as Level 2 and is based on observed or quoted market prices for the same or similar issues, or based 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. 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, 2024 plus an applicable spread, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank.

For cash and cash equivalents, restricted cash and short-term investments and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments.

3. Derivative instruments:

We use commodity derivatives to manage our exposure to fluctuation in the market price of natural gas. Our risk management and compliance committee provides general oversight over all derivative activities. We do not apply hedge accounting to derivative transactions, but instead apply regulated operations accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps are reflected as regulatory assets or liabilities, as appropriate. Realized gains and losses on natural gas swaps are included in fuel expense within our consolidated statements of revenues and expenses and, therefore, net margins within our consolidated statements of cash flows.

We are exposed to credit risk as a result of entering into these 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 could cause us to have credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of December 31, 2024 all of the counterparties with transaction amounts outstanding under our derivative 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 derivative 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.

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, 2024 and 2023, the estimated fair values of our natural gas contracts were net assets of \$28,624,000 and \$13,445,000, respectively.

As of December 31, 2024, one of our counterparties was required to post credit collateral totaling \$500,000 under our natural gas swap agreements. Such posted collateral is classified as restricted cash and included in the Restricted cash and short-term investments line items within our consolidated balance sheets. As of December 31, 2023, none of our counterparties were required to post credit collateral under our natural gas swap agreements.

The following table reflects the volume activity of our natural gas derivatives as of December 31, 2024 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2025	26.1
2026	22.8
2027	11.8
2028	1.2
2029	1.5
Total	63.4

The table below reflects the fair value of derivative instruments subject to the right of setoff and their effect on our consolidated balance sheets at December 31, 2024 and 2023. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of setoff exists.

Consolidated Balance Sheet Location		Fair Value					
		2024		2023			
		Assets	Liabilities	Net Carrying Value Presented on the Balance Sheet	Assets	Liabilities	Net Carrying Value Presented on the Balance Sheet
Assets		(dollars in thousands)					
Natural gas swaps	Other current assets	\$ 19,527	\$ (1,563)	\$ 17,964	\$ —	\$ —	\$ —
Natural gas swaps	Other deferred charges	17,566	(5,279)	12,287	32,177	(6,718)	25,459
Liabilities							
Natural gas swaps	Other current liabilities	\$ 290	\$ (1,917)	\$ (1,627)	\$ 3,798	\$ (14,168)	\$ (10,370)
Natural gas swaps	Other deferred credits	—	—	—	—	(1,644)	(1,644)
Total		\$ 37,383	\$ (8,759)	\$ 28,624	\$ 35,975	\$ (22,530)	\$ 13,445

The following table presents the realized gains and (losses) on derivative instruments recognized in margin for the years ended December 31, 2024, 2023 and 2022.

	Consolidated Statement of Revenues and Expenses Location	2024			2023			2022		
		(dollars in thousands)								
Natural gas swaps gains	Fuel	\$	1,213	\$	2,001	\$	121,626			
Natural gas swaps losses	Fuel		(25,510)		(22,924)		(6,587)			
Total		\$	(24,297)	\$	(20,923)	\$	115,039			

The following table presents the unrealized (gains) and losses on derivative instruments deferred on the consolidated balance sheets at December 31, 2024 and 2023.

	<u>Consolidated Balance Sheet Location</u>	(dollars in thousands)	
		2024	2023
Natural gas swaps	Regulatory liability	\$ 28,624	\$ 13,445
Total		\$ 28,624	\$ 13,445

4. Investments:

Investments in debt and equity securities

Investment securities we hold are recorded at fair value in the accompanying consolidated balance sheets. We apply regulated operations accounting to the unrealized gains and losses of all investment securities. All realized and unrealized gains and losses are determined using the specific identification method.

The following tables summarize debt and equity securities at December 31, 2024 and 2023.

2024	(dollars in thousands)			
	Gross Unrealized			
	Cost	Gains	Losses	Fair Value
Equity	\$ 259,554	\$ 231,815	\$ (6,385)	\$ 484,984
Debt	864,575	3,209	(17,336)	850,448
Other	155,802	224	(96)	155,930
Total	\$ 1,279,931	\$ 235,248	\$ (23,817)	\$ 1,491,362

2023	(dollars in thousands)			
	Gross Unrealized			
	Cost	Gains	Losses	Fair Value
Equity	\$ 344,669	\$ 246,795	\$ (5,549)	\$ 585,915
Debt	908,316	3,938	(25,181)	887,073
Other	2,889	61	(36)	2,914
Total	\$ 1,255,874	\$ 250,794	\$ (30,766)	\$ 1,475,902

The cost basis of our debt securities that were in unrealized loss positions at December 31, 2024 was \$688,233,000. At December 31, 2024, \$2,874,000 of the \$17,336,000 of unrealized losses relates to securities that have been in unrealized loss positions for less than twelve months and \$14,462,000 relates to securities that have been in unrealized loss positions for greater than twelve months. These unrealized losses are primarily attributable to increases in market interest rates.

The contractual maturities of debt securities, which are included in the estimated fair value table above, at December 31, 2024 and 2023 are as follows:

	(dollars in thousands)			
	2024		2023	
	Cost	Fair Value	Cost	Fair Value
Due within one year	\$ 489,744	\$ 488,062	\$ 486,602	\$ 477,726
Due after one year through five years	188,519	185,714	267,690	260,193
Due after five years through ten years	63,526	62,123	47,804	47,416
Due after ten years	122,785	114,549	106,220	101,738
Total	\$ 864,574	\$ 850,448	\$ 908,316	\$ 887,073

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2024, 2023 and 2022:

	(dollars in thousands)		
	2024	2023	2022
Gross realized gains	\$ 101,549	\$ 15,518	\$ 10,029
Gross realized losses	(11,193)	(8,564)	(31,979)
Proceeds from sales	1,484,525	720,186	301,128

Investment in associated companies

Investments in associated companies were as follows at December 31, 2024 and 2023:

	(dollars in thousands)	
	2024	2023
National Rural Utilities Cooperative Finance Corporation (CFC)	\$ 23,983	\$ 24,068
CT Parts, LLC	6,561	6,568
Georgia Transmission Corporation	44,936	40,806
Georgia System Operations Corporation	7,250	6,500
Other	3,990	4,191
Total	\$ 86,720	\$ 82,133

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 and they are valued at cost. The investment in Georgia Transmission represents capital credits valued at cost. The investment in Georgia System Operations represents loan advances. Repayments of these advances are due by December 2028.

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. Pursuant to a payment undertaking agreement, we have a guarantee for the annual basic rent payments due under the remaining lease. The fair value amount relating to the guarantee of basic rent payment is immaterial to us principally due to the high credit rating of the payment undertaker, Rabobank Nederland. The basic rental payments remaining through the end of the lease, which expires in 2027, are approximately \$9,267,000.

At the end of the term of the remaining facility lease, we have the option to cause RMLC to purchase the owner trust's undivided interest in Rocky Mountain at a fixed purchase option price of approximately \$112,000,000. The payment undertaking agreement, along with the equity funding agreement with AIG Matched Funding Corp., would fund approximately \$74,000,000 and \$37,928,000 of this amount, respectively, and these amounts would be paid to the owner trust over five installments in 2027. If we do not elect to cause RMLC to purchase the owner trust's undivided interest in Rocky Mountain, Georgia Power has an option to purchase the undivided interest. If neither we nor Georgia Power exercise our purchase option, and we return (through RMLC) the undivided interest in Rocky Mountain to the owner trust, the owner trust has several options it can elect, including:

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

Under the first two of these options we must arrange new financing for the outstanding amount of the loan used to finance the owner trust's upfront rental payment made to us when the lease closed on December 31, 1996. At the end of the lease term, the amount of the outstanding loan is anticipated to be approximately \$74,000,000. If new financing cannot be arranged, the owner trust can ultimately cause us to purchase 49%, in the case of the first option above, or all, in the case of the second option above, of the loan certificate or cause RMLC to exercise its purchase option or RMLC to renew the facility lease and facility sublease, respectively.

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 the state 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 our 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:

	2024	2023	2022
Statutory federal income tax rate	21.0 %	21.0 %	21.0 %
Patronage exclusion	(21.0)%	(21.0)%	(21.0)%
Effective income tax rate	0.0 %	0.0 %	0.0 %

The components of our net deferred tax assets and liabilities as of December 31, 2024 and 2023 were as follows:

	(dollars in thousands)	
	2024	2023
Deferred tax assets		
Net operating losses	\$ 157,190	\$ 109,447
Obligation related to asset retirements	319,040	375,530
Advance payments	142,949	176,956
Other regulatory liabilities	36,973	23,652
Other assets	13,026	30,085
Deferred tax assets	669,178	715,670
Less: Valuation allowance	—	—
Net deferred tax assets	\$ 669,178	\$ 715,670
Deferred tax liabilities		
Fixed assets and intangibles	\$ (175,777)	\$ (154,219)
Right-of-use assets-finance leases	(75,508)	(77,923)
Other regulatory asset	(338,048)	(373,802)
Other liabilities	(19,024)	(15,679)
Deferred tax liabilities	(608,357)	(621,623)
Net deferred tax assets (liabilities)	\$ 60,821	\$ 94,047
Less: Patronage exclusion	(60,821)	(94,047)
Net deferred taxes	\$ —	\$ —

As of December 31, 2024, we have federal net operating loss carryforwards of \$630,218,000 which may be carried forward indefinitely. Due to the tax basis method for allocating patronage dividends, we will utilize this loss to offset any future federal taxable income prior to member allocation per the bylaws. There is no net impact to the deferred tax asset after the patronage exclusion.

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 2021 and 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 2021 and forward. We have no liabilities recorded for uncertain tax positions.

6. Leases:

As a lessee, we have a relatively small portfolio of leases with the most significant being our 60% undivided interest in Scherer Unit No. 2 and railcar leases for the transportation of coal. We also have various other leases of minimal value.

We classify our four Scherer Unit No. 2 leases as finance leases and our railcar leases as operating leases. We have made an accounting policy election not to recognize right-of-use assets and lease liabilities that arise from short-term leases, leases having an initial term of 12 months or less, for any class of underlying asset. We recognize lease expense for short-term leases on a straight-line basis over the lease term. Lease expense recognized for our short-term leases during 2024 and 2023 was insignificant.

Finance Leases

Three of our Scherer Unit No. 2 finance leases have lease terms through December 31, 2027, and one lease extends through June 30, 2031. At the end of the leases, we can elect at our sole discretion to:

- Renew the leases for a period of not less than one year and not more than five years at fair market value,
- Purchase the undivided interest at fair market value, or
- Redeliver the undivided interest to the lessors.

For rate-making purposes, we include the actual lease payments for our finance leases in our cost of service. The difference between lease payments and the aggregate of the amortization on the right-of-use asset and the interest on the finance lease obligation is recognized as a regulatory asset. Finance lease amortization is recorded in depreciation and amortization expense.

Operating Leases

Our railcar operating leases have terms that extend through November 30, 2028. At the end of the railcar operating leases, we can renew at terms mutually agreeable by us and the lessors, purchase the assets or return the assets to the lessors. We have additional operating leases including one for office equipment that has a term extending through November 30, 2029 and one for real property at one of our electric generating facilities that has a term extending through February 2042 with one renewal option for a 20-year term.

The exercise of renewal options for our finance and operating leases is at our sole discretion.

As all of our operating leases do not provide an implicit rate, we use our incremental borrowing rate based on the information available at the time new lease agreements are entered into or reassessed to determine the present value of lease payments.

We combine lease and nonlease components for all lease agreements.

Classification	2024	2023
	(dollars in thousands)	
Right-of-use assets - Finance leases		
Right-of-use assets	\$ 302,732	\$ 302,732
Less: Accumulated provision for depreciation	(283,417)	(278,586)
Total finance lease assets	<u>\$ 19,315</u>	<u>\$ 24,146</u>
Lease liabilities - Finance leases		
Obligations under finance leases	\$ 33,173	\$ 43,586
Long-term debt and finance leases due within one year	10,413	9,351
Total finance lease liabilities	<u>\$ 43,586</u>	<u>\$ 52,937</u>

Classification	2024	2023
	(dollars in thousands)	
Right-of-use assets - Operating leases		
Electric plant in service, net	\$ 7,723	\$ 6,587
Total operating lease assets	<u>\$ 7,723</u>	<u>\$ 6,587</u>

Lease liabilities - Operating leases		
Capitalization - Other	\$ 5,715	\$ 5,152
Other current liabilities	1,954	1,529
Total operating lease liabilities	<u>\$ 7,669</u>	<u>\$ 6,681</u>

Lease Cost	Classification	2024	2023
		(dollars in thousands)	
Finance lease cost:			
Amortization of leased assets	Depreciation and amortization	\$ 9,351	\$ 8,398
Interest on lease liabilities	Interest expense	\$ 5,598	\$ 6,551
Operating lease cost	Inventory ⁽¹⁾ & production expense	\$ 2,287	\$ 1,441
Total lease cost		<u>\$ 17,236</u>	<u>\$ 16,390</u>

(1) The majority of our operating lease costs relate to our railcar leases and such costs are added to the cost of our fossil-fuel inventories and are recognized in fuel expense as the inventories are consumed.

	December 31, 2024	December 31, 2023
Lease Term and Discount Rate		
Weighted-average remaining lease term (in years):		
Finance leases	4.37	5.26
Operating leases	5.01	5.77
Weighted-average discount rate:		
Finance leases	11.05 %	11.05 %
Operating leases	6.34 %	6.37 %

	2024	2023
	(dollars in thousands)	
Other Information:		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance leases	\$ 5,598	\$ 6,551
Operating cash flows from operating leases	\$ 2,381	\$ 1,410
Financing cash flows from finance leases	\$ 9,351	\$ 8,398
Right-of-use assets obtained in exchange for new operating lease liabilities	\$ 2,951	\$ 4,503

Maturity analysis of our finance and operating lease liabilities as of December 31, 2024 is as follows:

Year Ending December 31,	(dollars in thousands)		
	Finance Leases	Operating Leases	Total
2025	\$ 14,949	\$ 2,388	\$ 17,337
2026	14,949	2,096	17,045
2027	14,949	1,819	16,768
2028	3,052	1,709	4,761
2029	3,052	263	3,315
Thereafter	4,579	723	5,302
Total lease payments	\$ 55,530	\$ 8,998	\$ 64,528
Less: imputed interest	(11,944)	(1,329)	(13,273)
Present value of lease liabilities	\$ 43,586	\$ 7,669	\$ 51,255

As a lessor, we primarily lease office space to several tenants within our headquarters building. Several of these tenants are related parties. We account for all of these lease agreements as operating leases.

Lease income recognized during 2024 and 2023 was as follows:

	2024	2023
	(dollars in thousands)	
Lease income	\$ 5,561	\$ 6,776

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) and first mortgage notes issued in conjunction with the sale by public authorities of pollution control revenue bonds (PCRBs). 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, and the first mortgage notes issued in conjunction with the sale of pollution control revenue bonds.

Maturities for long-term debt and finance lease obligations through 2029 are as follows:

	(dollars in thousands)				
	2025	2026	2027	2028	2029
FFB	\$ 285,536	\$ 273,477	\$ 249,492	\$ 292,985	\$ 340,149
FMBs	62,500	62,500	62,500	62,500	62,500
PCRBs ⁽¹⁾	40,530	—	—	—	—
	\$ 388,566	\$ 335,977	\$ 311,992	\$ 355,485	\$ 402,649
Finance Leases	10,413	11,595	12,912	2,153	2,397
Total	\$ 398,979	\$ 347,572	\$ 324,904	\$ 357,638	\$ 405,046

(1) Represents amounts that would be due in the current year upon optional tender by holders of the Series 2013A Appling bonds. These bonds have a provision that holders of the bonds may tender the bonds for purchase at any time upon at least seven days notice, and we are obligated to pay the purchase price of the bonds tendered for purchase and not remarketed. These Series 2013A Appling bonds, totaling \$40,530,000, have a nominal maturity in 2038. There are no scheduled debt maturities for the PCRBs through 2029.

The weighted average interest rate on our long-term debt at December 31, 2024 and 2023 was 3.95% and 3.89%, respectively. The weighted average interest rate on our short-term borrowings at December 31, 2024 and 2023 was 4.80% and 5.72%, respectively.

Long-term debt outstanding, excluding commercial paper reclassified to long-term debt, and the associated unamortized debt issuance costs and debt discounts at December 31, 2024 and December 31, 2023 are as follows:

	2024		2023	
	Principal	Unamortized Debt Issuance Costs and Debt Discounts	Principal	Unamortized Debt Issuance Costs and Debt Discounts
	(dollars in thousands)			
FFB	\$ 6,846,935	\$ 48,947	\$ 6,841,352	\$ 51,083
FMBs	4,837,500	63,373	4,551,010	60,987
PCRBs	704,190	8,008	704,190	8,490
	\$ 12,388,625	\$ 120,328	\$ 12,096,552	\$ 120,560

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, we and the U.S. Department of Energy, acting by and through the Secretary of Energy, entered into a Loan Guarantee Agreement in 2014 pursuant to which the Department of Energy agreed to guarantee our obligations under a Note Purchase Agreement (the Original Note Purchase Agreement), among us, the Federal Financing Bank and the Department of Energy and two future advance promissory notes made by us to the Federal Financing Bank in the aggregate amount of \$3,057,069,461 (the Original FFB Notes and together with the Original Note Purchase Agreement, the Original FFB Documents).

In 2019, we and the Department of Energy entered into an Amended and Restated Loan Guarantee Agreement (as amended, the Loan Guarantee Agreement) which increased the aggregate amount guaranteed by the Department of Energy to \$4,676,749,167. We also entered into a Note Purchase Agreement (the Additional Note Purchase Agreement), among us, the Federal Financing Bank and the Department of Energy and a future advance promissory note made by us to the Federal Financing Bank in the amount of \$1,619,679,706 (the Additional FFB Note and together with the Additional Note Purchase Agreement, the Additional FFB Documents).

Together, the Original FFB Documents and Additional FFB Documents provide for a term loan facility (the Facility) under which we borrowed a total of \$4,633,028,088. We received our final advance under the Facility in December 2022. Interest is payable quarterly in arrears and principal payments on all advances under the FFB Notes began in February 2020. As of December 31, 2024, we have repaid \$582,384,348 of principal on the FFB Notes and the aggregate Department of Energy-guaranteed borrowings outstanding, including capitalized interest, totaled \$4,050,643,740. The final maturity date is February 20, 2044. We may voluntarily prepay outstanding borrowings under the Facility. Under the FFB Documents, any prepayment will be subject to a make-whole premium or discount, as applicable. Any amounts prepaid may not be re-borrowed.

Under the Loan Guarantee Agreement, we are obligated to reimburse the Department of Energy in the event it is required to make any payments to the Federal Financing Bank under its guarantee. Our payment obligations to the Federal Financing Bank under the FFB Notes and reimbursement obligations to the Department of Energy under its guarantee, but not our covenants to the Department of Energy under the Loan Guarantee Agreement, are secured equally and ratably with all of our other obligations issued under our first mortgage indenture.

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, referred to as an "Alternate Amortization Event," at the Department of Energy's option we will be required to repay the outstanding principal amount of all borrowings under the Facility over a period of five years, with level principal amortization. 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.

b) Rural Utilities Service Guaranteed Loans:

During 2024, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling \$317,493,000, consisting of \$212,035,000 for long-term financing of general and environmental improvements at existing plants and \$105,458,000 for the Washington County and Baconton acquisition loans.

In January 2025, we received an additional \$40,398,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

c) Credit Facilities:

In May 2024, we amended our syndicated line of credit facility among eleven lenders, including National Rural Utilities Cooperative Finance Corporation, as administrative agent to extend the maturity date for five years to May 2029. In connection with this amendment, we increased the available amount under the credit agreement to \$1,275,000,000 from \$1,210,000,000.

In September 2024, we amended our JPMorgan Chase Bank, N.A. line of credit facility to extend the maturity date to March 2027. In connection with this amendment, we decreased the available amount under the credit agreement to \$200,000,000 from \$350,000,000.

Both of the above renewed credit agreements contain customary representations, warranties, covenants, events of default and acceleration, including financial covenants to maintain patronage capital of at least \$900,000,000, previously \$750,000,000 and limits our unsecured indebtedness, as defined by the credit agreement, at \$4,000,000,000. At December 31, 2024, our actual patronage capital was \$1,328,418,000 and we had \$401,801,000 of unsecured indebtedness outstanding.

As of December 31, 2024, we had a total of \$1,725,000,000 of committed credit arrangements comprised of four separate facilities with maturity dates that range from March 2027 to May 2029. 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, 2024, we had the ability to issue letters of credit totaling \$810,000,000 in the aggregate, of which \$807,000,000 remained available. At December 31, 2024, we had (i) \$2,504,000 under these lines of credit in the form of issued letters of credit and (ii) \$401,801,000 dedicated under one of these lines of credit to support a like face value of commercial paper that was outstanding.

d) Green First Mortgage Bonds:

In June 2024, we issued \$350,000,000 of 5.800% green first mortgage bonds, Series 2024A, to provide for long-term financing or refinancing of expenditures related to Vogtle Units No. 3 and No. 4, including refinancing principal payments on our Department of Energy-guaranteed loans that were made prior to Vogtle Unit No. 4's in-service date. In conjunction with the issuance of the bonds, we repaid \$346,014,000 of outstanding commercial paper. The bonds are due to mature in June 2054 and are secured under our first mortgage indenture.

In January 2025, we issued \$350,000,000 of 5.900% green first mortgage bonds, Series 2025A, to provide for long-term financing or refinancing of expenditures related to Vogtle Units No. 3 and No. 4, including refinancing principal payments on our Department of Energy-guaranteed loans that were made prior to Vogtle Unit No. 4's in-service date. In conjunction with the issuance of the bonds, we repaid \$254,463,000 of outstanding commercial paper. The bonds are due to mature in February 2055 and are secured under our first mortgage indenture.

e) Pollution Control Revenue Bonds:

In February 2025, we remarketed \$312,760,000 of term-rate pollution control revenue bonds that were issued on our behalf by the Development Authorities of Appling, Burke and Monroe Counties which were subject to mandatory tender at that time. This included \$272,230,000 million of Burke and Monroe bonds which we remarketed as five-year term-rate bonds, and \$40,530,000 million of Series 2013A Appling bonds, which we converted to a weekly rate mode without external credit or liquidity support. We added a provision to the Appling bonds that permits holders of the bonds to tender their bonds for purchase at any time upon at least seven days notice, and obligates us to pay the purchase price of the bonds tendered for purchase that are not remarketed. Since the Series 2013A Appling bonds now contain a provision that could accelerate their payment to the current year under certain circumstances, at December 31, 2024, we reclassified these bonds from the Long-term debt line item to the Long-term debt and finance leases due within one year line item within our consolidated balance sheets.

Our obligation to pay the principal and interest on all these pollution control bonds is secured under our first mortgage indenture, and additionally, our obligation to pay the purchase price on the Series 2013A Appling bonds is also secured under our first mortgage indenture.

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, 2024 and 2023 is as follows:

Plant	2024		2023	
	Investment	Accumulated Depreciation	Investment	Accumulated Depreciation
(dollars in thousands)				
In-service⁽¹⁾				
Owned property				
Vogtle Units No. 1 & No. 2 (Nuclear – 30% ownership)	\$ 2,941,737	\$ (1,958,308)	\$ 3,035,806	\$ (1,948,158)
Vogtle Units No. 3 and No. 4 (Nuclear – 30% ownership) ^(2,3)	7,966,038	(153,949)	4,771,526	(43,418)
Hatch Units No. 1 & No. 2 (Nuclear – 30% ownership)	912,629	(558,916)	1,019,809	(559,001)
Wansley Units No. 1 & No. 2 (Fossil – 30% ownership)	26,603	(23,344)	24,710	(27,152)
Scherer Unit No. 1 (Fossil – 60% ownership)	1,369,982	(690,307)	1,372,241	(660,580)
Doyle (Combustion Turbine - 100% ownership)	151,697	(130,479)	148,902	(127,378)
Rocky Mountain Units No. 1, No. 2 & No. 3 (Hydro – 75% ownership)	619,581	(319,528)	618,955	(308,827)
Hartwell (Combustion Turbine - 100% ownership)	239,570	(134,649)	233,662	(131,434)
Hawk Road (Combustion Turbine - 100% ownership)	277,099	(84,004)	272,416	(79,985)
Talbot (Combustion Turbine - 100% ownership)	310,826	(172,890)	308,837	(167,033)
Chattahoochee (Combined cycle - 100% ownership)	354,570	(172,094)	343,531	(168,292)
BC Smith (Combined cycle - 100% ownership)	413,829	(119,228)	352,005	(126,886)

Plant	2024		2023	
	Investment	Accumulated Depreciation	Investment	Accumulated Depreciation
TA Smith (Combined cycle - 100% ownership)	702,383	(243,554)	689,198	(228,997)
Washington County (Combustion Turbine – 100% ownership)	171,937	(94,418)	171,034	(92,498)
Baconton (Combustion Turbine – 100% ownership)	33,910	(16,900)	32,987	(16,379)
Walton County (Combustion Turbine – 100% ownership)	121,718	(43,697)	—	—
Transmission plant	173,183	(77,295)	122,452	(65,784)
Other	103,785	(64,004)	101,061	(60,710)
Property under finance lease:				
Scherer Unit No. 2 (Fossil – 60% leasehold)	800,131	(644,063)	795,698	(606,226)
Total in-service	\$ 17,691,208	\$ (5,701,627)	\$ 14,414,830	\$ (5,418,738)

Construction work in progress	2024	2023
Hatch Units No. 1 & No. 2 (Nuclear – 30% ownership)	\$ 29,563	\$ 42,825
Scherer Unit No. 1 (Fossil – 60% ownership)	42,774	16,077
Vogtle Units No. 1 & No. 2 (Nuclear – 30% ownership)	22,842	27,368
Vogtle Units No. 3 and No. 4 (Nuclear – 30% ownership) ^(2,3)	10,623	3,128,720
Wansley Units No. 1 & No. 2 (Fossil – 30% ownership)	152	46
Environmental and other generation improvements	214,213	79,605
Total construction work in progress	\$ 320,167	\$ 3,294,641

(1) Amounts include plant acquisition adjustments at December 31, 2024 of \$330,730,000 and December 31, 2023 of \$290,725,000.

(2) Plant Vogtle Unit No. 3 was placed in service on July 31, 2023.

(3) Plant Vogtle Unit No. 4 was placed in service on April 29, 2024.

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 consolidated statements of revenues and expenses.

b. Plant Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), 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 under construction at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company, Inc. as its agent for licensing, engineering, procurement and contract management.

Georgia Power placed Unit No. 3 in service on July 31, 2023 and placed Unit No. 4 in service on April 29, 2024.

Our ownership interest and proportionate share of the cost to construct Vogtle Units No. 3 and No. 4 is 30%, representing approximately 660 megawatts. As of December 31, 2024, our actual costs related to the new Vogtle units were approximately \$8.3 billion, net of \$1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and approximately \$433 million we received from Georgia Power pursuant to the cost-sharing provisions in a settlement agreement with Georgia Power. We estimate that our proportionate share of remaining additional capital costs to be incurred on the project through the end of 2025 to be \$10-\$15 million.

Plant Vogtle Unit No. 3 and No. 4 Production Tax Credits

In 2024 and 2023, since Plant Vogtle Units No. 3 and No. 4 were placed in service, we sold to Georgia Power approximately \$72,600,000 and \$21,700,000, respectively, of nuclear production tax credits ("NPTCs"), earned by us pursuant to Section 45J of the Internal Revenue Code and recognized the amounts as credits to the Production expense line item within our consolidated statements of revenues and expenses.

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. 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 \$2,324,000, \$2,143,000 and \$2,017,000 in 2024, 2023 and 2022, 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. Our contributions to the employer retirement contribution feature of the 401(k) plan were approximately \$6,251,000, \$5,655,000 and \$5,098,000 in 2024, 2023 and 2022, respectively.

We also sponsor two deferred compensation plans for eligible employees. Eligible employees are defined as highly compensated individuals within the definition of the Internal Revenue Code. The plans offer investment options to all eligible participants without regard to salary limits. In addition, one plan enables us to continue employer retirement contributions to highly compensated employees who exceed Internal Revenue Code salary limits for retirement plan contributions. The value of the plans is recorded as an asset and an equal offsetting liability with balances of \$6,952,000 and \$5,723,000 in 2024 and 2023, respectively.

10. Nuclear insurance:

The Price-Anderson Act limits public liability claims that could arise from a single nuclear incident to \$16.3 billion. This amount is covered by private insurance and a mandatory program of deferred premiums that could be assessed against all owners of nuclear power reactors. Such private insurance provided by American Nuclear Insurers (ANI), 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 \$500 million, a licensee of a nuclear power plant could be assessed a deferred premium of up to \$166 million per incident for each licensed reactor operated by it, but not more than \$25 million per reactor per incident to be paid in a calendar year. On the basis of our ownership interest in six nuclear reactors, we could be assessed a maximum of \$299 million per incident, but not more than \$44 million in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every 5 years, and exclude any applicable state premium taxes. The next scheduled adjustment is due no later than November 1, 2028.

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 \$1.5 billion for members' operating nuclear generating facilities. Additionally, there is coverage through NEIL for decontamination, excess property insurance, and premature decommissioning coverage up to \$1.25 billion for

nuclear losses and policies providing coverage up to \$750 million for non-nuclear losses in excess of the \$1.5 billion primary coverage.

NEIL also covers the additional costs that could be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of \$490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted.

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 maximum annual assessment for Oglethorpe based on ownership share, is limited to approximately \$50 million.

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

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are 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:

We have entered into long-term commitments to meet fuel, transportation, maintenance and asset retirement requirements.

To supply a portion of the fuel requirements to our co-owned generating units, Georgia Power, on our behalf for coal and Southern Nuclear on our behalf for nuclear fuel, 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.

We have entered into long-term agreements with various counterparties to provide firm natural gas transportation to our natural gas-fired facilities. The value of these agreements is based on fixed rates as provided in the contracts and does not include variable costs.

We have also entered into long-term maintenance agreements for certain of our natural gas-fired facilities. In most cases, these agreements include provisions for price escalation and performance bonuses and, if applicable, are included in the values; timing of expenditures is based on current operational assumptions. Certain agreements contain significant cancellation for convenience penalties and, therefore, amounts in the table below include total estimated expenditures over the life of the agreement. If these agreements were terminated by us in 2025 for convenience, our cancellation obligation would be approximately \$66,866,000.

We have asset retirement obligations which are legal obligations to retire long-lived assets. These obligations are primarily for the decommissioning of our nuclear units and coal ash ponds. Expenditures are based on estimates

determined through decommissioning studies and include provisions for price escalation and other factors. See Note 1h for information regarding our asset retirement obligations.

We have a small portfolio of leases with the most significant being a finance lease for our 60% undivided interest in Scherer Unit No. 2. In addition, we have other operating leases including railcar leases for the transportation of coal at our coal-fired plant and various other leases of minimal value. For information regarding these leases, see Note 6.

As of December 31, 2024, our estimated commitments are as follows:

	(dollars in thousands)						
	Coal	Nuclear Fuel	Gas Transportation	Maintenance Agreements	Asset Retirement Obligations	Finance and Operating Leases	
2025	\$ 21,349	\$ 91,650	\$ 68,568	\$ 96,851	\$ 56,811	\$ 17,337	
2026	14,321	50,010	72,032	15,019	49,386	17,045	
2027	7,189	30,930	72,328	2,508	43,935	16,768	
2028	—	38,280	93,565	51,743	30,331	4,761	
2029	—	29,730	217,694	56,014	42,380	3,315	
Thereafter	—	48,810	3,556,334	223,583	10,639,479	5,302	

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.

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 may also become subject to climate change regulations that impose restrictions on emissions of greenhouse gases, including carbon dioxide.

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 proposed or potential 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. Plant Acquisition:

Walton County Power Plant

On June 28, 2024, we acquired Walton County Power, LLC, which owns the Walton County Power Plant, located near Monroe, Georgia, from Mackinaw Power, LLC, an affiliate of the Carlyle Group, Inc. Walton is a three-unit 450-megawatt natural gas-fired combustion turbine facility. In October 2024, we assumed direct ownership of the facility and eliminated Walton County Power, LLC.

The purchase price was \$75,418,000 and other costs associated with the transaction were approximately \$2,588,000 (consisting primarily of spare parts, legal and professional services). We accounted for the acquisition as an asset acquisition. We financed the acquisition on an interim basis through the issuance of commercial paper and submitted a loan application to the Rural Utilities Service for long-term financing. For any amounts not funded through the Rural Utilities Service, we intend to issue first mortgage bonds. We expect that any financing from the Rural Utilities Service or through first mortgage bonds will be secured under our first mortgage indenture.

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

Classification

	(dollars in thousands)
Recognized identifiable assets acquired and liabilities assumed:	
Electric plant in service, net	\$ 76,730
Other current assets	667
Other current liabilities	(1,979)
Total identifiable net assets	\$ 75,418

Some of our members elected to take service (scheduling members) at the date of acquisition and some members have elected to defer (deferring members) their share of output through a date no later than January 2028. Prior to the deferring members' use of Walton, their share of output is being sold into the wholesale market. Residual net results of operations, including related interest costs of deferring members are deferred as a regulatory asset. This regulatory asset will be amortized over the then remaining life of the plant, estimated to be 24 years at January 2028. Amortization of a deferring member's share of the regulatory asset will begin upon taking service. Revenues and costs of output associated with scheduling members are being recognized in the current period.

14. Other Future Power Resources:

Natural Gas Capacity Agreements

We have executed precedent agreements with Southern Natural Gas Company, LLC (SONAT) that became effective in August 2024. The agreements provide for firm natural gas transportation needed to serve our new Smarr combined cycle generation facility and additional firm transportation to our BC Smith Energy Facility. In November 2024, we exercised options to increase the available amounts under the precedent agreements to provide additional natural gas supply to the new Smarr facility. The firm transportation capacity is contingent upon completion of these expansion projects by SONAT. With the exercise of the options noted above, total fixed charges over the 20-year base terms will be approximately \$2,100,000,000. Our obligation to make payments begins when the pipeline expansion projects are placed into service, both of which are projected to be November 2028.

In October 2024, we entered into a preliminary binding agreement with Tennessee Gas Pipeline Company, L.L.C. to commit for natural gas capacity for the Mississippi Crossing gas pipeline. This agreement will provide capacity for both existing and future resources. The firm transportation capacity is contingent upon completion of this expansion project. Total fixed charges over the 20-year base term are currently approximately \$900,000,000, although may increase to approximately \$1,000,000,000 based on changes to the applicable receipt and delivery

points as the terms of the agreement are finalized during the first quarter of 2025. Our obligation to make payments begins when the pipeline project is placed into service, which is projected to be November 2028.

15. Reportable Segment Information:

An operating segment is generally defined as a component of a business for which discrete financial information is available and whose operating results are regularly reviewed by the chief operating decision maker ("CODM"). We report our segment information in the same way that management internally organizes our business for assessing performance and making decisions regarding the allocation of resources in accordance with ASC 280, Segment Reporting. We have one reportable operating segment.

As an electric membership cooperative, our single reportable operating segment is providing wholesale electric service to our members, primarily from our diverse energy portfolio of generation assets. Our operating revenues are derived primarily from wholesale power contracts we have with each of our 38 members. Pursuant to our contracts, we primarily provide two services, capacity and energy.

Our Chief Operating Decision Maker is identified as our President and Chief Executive Officer because our CODM has the final authority over performance assessment and resource allocation decisions. Due to our diverse energy portfolio of generation assets, our CODM regularly receives and uses discrete financial information about our single reportable segment in our CODM's performance assessment and resource allocation decisions, predominantly in the budgeting and forecasting process.

Our CODM manages our business on a consolidated basis and uses "net margin" as reported within our consolidated statements of revenues and expenses to allocate resources and assess performance. Segment net margin is determined on the same basis as net margin presented within our consolidated financial statements.

Within our reportable operating segment, there are significant expense categories regularly provided to the CODM and included in the measure of our segment's net margin. Our reportable segment's significant expenses include fuel expense, production expense, depreciation and amortization and interest expense as reported within our consolidated statements of revenues and expenses and notes to our consolidated financial statements. Our CODM uses these identified significant segment expenses and other segment information, including capacity and energy sales to members and investment income when allocating resources accordingly and assessing performance of all our generating assets to provide environmentally responsible, safe, reliable and affordable electricity to our members.

Fuel expense primarily includes nuclear fuel burn, coal inventory burn, natural gas purchases, natural gas transportation charges, and settlement of our natural gas derivatives.

Production expense primarily includes operation and maintenance, major maintenance outage expenses for our generating fleet of assets, and administrative and general expenses.

Depreciation expense is computed on additions when they are placed in service using the composite straight-line method and considered a significant segment expense as it is a measure of the remaining useful lives of our generating assets.

Interest expense is considered a significant segment expense as we are exposed to the risk of changes in interest rates relating to a portion of our debt.

The accounting policies of our reportable segment are the same as those described in Note 1, Summary of significant accounting policies.

The measure of our segment's assets is reported within our consolidated balance sheets as "total assets". Our segment asset line items, provided to our CODM, are consistent with those reported within our consolidated balance sheets.

16. Quarterly financial data (unaudited):

Summarized quarterly financial information for 2024 and 2023 is as follows:

	<u>First Quarter</u>	<u>Second Quarter</u>	<u>Third Quarter</u>	<u>Fourth Quarter</u>
	(dollars in thousands)			
2024				
Operating revenues	\$ 536,314	\$ 564,090	\$ 540,670	\$ 540,773
Operating margin	120,231	125,140	125,545	112,580
Net margin	42,099	24,191	10,560	(6,349)
2023				
Operating revenues	\$ 389,453	\$ 389,389	\$ 500,776	\$ 460,567
Operating margin	57,006	49,987	92,317	77,756
Net margin	24,410	18,414	27,127	(4,161)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and statements of capitalization of Oglethorpe Power Corporation (the Company) as of December 31, 2024 and 2023, the related consolidated statements of revenues and expenses, patronage capital and membership fees and cash flows for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with U.S. generally accepted accounting principles..

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical

audit matter below, providing a separate opinion on the critical audit matter or on the account or disclosure to which it relates.

Description of the Matter

Valuation of asset retirement obligations related to nuclear decommissioning

As described in Note 1h of the consolidated financial statements, the Company has legal obligations associated with the future decommissioning of its nuclear facilities. Each asset retirement obligation recorded represents the present value of the estimated future costs expected to be incurred during decommissioning discounted using a credit-adjusted risk-free rate. The nuclear decommissioning cost estimates are based on site studies and assume the prompt dismantlement and removal of the radiated portions of the plant from service, as well as management of spent fuel. At December 31, 2024, the Company's asset retirement obligations related to nuclear decommissioning totaled \$812.2 million.

Auditing the valuation of asset retirement obligations related to nuclear decommissioning is complex due to the judgmental nature of certain assumptions used in determining the liability, including the projected timing of when the assets will be retired and ultimately be decommissioned, the amount of estimated future dismantling and removal costs for the radiated structures of the plant, the amount of estimated spent fuel management costs, and the factors used to reflect how the estimated costs will be escalated with inflation.

How We Addressed the Matter in Our Audit

To test the valuation of asset retirement obligations related to nuclear decommissioning, we performed audit procedures that included, among others, assessing the methodology used by the Company, testing the significant assumptions described above, and testing the accuracy of management's calculations. We involved engineering specialists, who assisted us in evaluating the Company's planned method of decommissioning, assessing the completeness of costs included in the cost estimates based upon the requirements of the applicable decommissioning regulations, comparing cost assumptions to available industry historical cost and licensing data, comparing decommissioning timing assumptions to U.S. nuclear power plant license renewal and plant closure data, and evaluating the professional qualifications and objectivity of management's third-party specialists.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2009.

Atlanta, Georgia
March 31, 2025

FINANCIAL AND STATISTICAL INFORMATION FOR 38 MEMBERS OF OGLETHORPE POWER CORPORATION

Our members 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 our members and the Rural Utilities Service or loan documents with other lenders. The Rural Utilities Service mortgage generally prohibits such distributions unless, after any such distribution, the member's total equity will equal at least 30% of its total assets, except that distributions may be made of up to 25% of the margins and patronage capital received by the member in the preceding year provided that equity is at least 20%.

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 such contracts to receive payment for power and energy supplied, we have no legal interest in, or obligations in respect of, any of the assets, liabilities, equity, revenues or margins of our members.

The following selected information on the individual members is intended to show, in the aggregate, the assets, liabilities, equity, revenues and margins of our members. Member assets, liabilities, equity, revenues and margins should not, however, be attributed to us. In addition, the revenues of our members are not pledged to us, but such revenues are received by the respective members and are the source from which moneys are derived by our members to pay for power and energy received from us. Revenues of our members are, however, pledged under their respective Rural Utilities Service mortgages or loan documents with other lenders.

The information contained in these tables was taken from Rural Utilities Service Financial and Statistical Reports (RUS Form 7) or similar reports prepared for other lenders or provided directly by a member. This information has not been independently verified by the Rural Utilities Service, any lender or us. The "Total" columns were not supplied or compiled by the Rural Utilities Service, any lender or our members. The "Total" column in each table is for informational purposes only, inasmuch as each member operates independently and is not responsible for the obligations of other members, except as provided in the wholesale power contracts (see "OUR BUSINESS — BUSINESS OVERVIEW — Wholesale Power Contracts" in the prospectus). In addition, the Times Interest Earned, Equity to Assets and Equity to Total Capitalization ratios were calculated by us from information obtained from each member's RUS Form 7 or other financial information provided to us, but the calculations were not independently verified by our members. No adjustments were made by us in calculating these ratios for items such as debt refinancings that are not reflected separately on the financial information provided to us.

For the calendar years 2021, 2022 and 2023, the information on the individual members is presented in the succeeding tables as follows:

- Table 1 - Selected Statistics,
- Table 2 - Average Number of Consumers Served,
- Table 3 - Annual Megawatt-hour Sales by Consumer Class,
- Table 4 - Annual Revenues by Consumer Class,
- Table 5 - Summary of Operating Results, and
- Table 6 - Condensed Balance Sheet Information.

**FINANCIAL AND STATISTICAL INFORMATION FOR THE
38 MEMBERS OF OGLETHORPE POWER CORPORATION**

**Table 1
SELECTED STATISTICS OF EACH MEMBER
(as of December 31)**

	Altamaha	Amicalola	Canoochee	Carroll	Central Georgia	Coastal	Cobb	Colquitt	Coweta- Fayette	Diverse
2023										
Avg. Monthly Residential Rev. (\$)	153.11	140.04	145.63	154.67	148.98	166.92	124.14	142.53	138.26	207.64
Avg. Monthly Residential kWh	988.00	1,167.00	1,103.00	1,140.00	1,218.00	1,180.00	1,069.00	1,126.00	1,184.00	1,179.00
Avg. Residential Rev.(cents per kWh)	15.50	12.00	13.20	13.57	12.23	14.15	11.62	12.65	11.68	17.61
Times Interest Earned Ratio ⁽¹⁾	5.54	2.41	2.88	6.76	2.11	4.24	7.13	3.47	4.53	2.01
Equity / Assets ⁽¹⁾	49 %	34 %	41 %	46 %	23 %	39 %	62 %	43 %	45 %	34 %
Equity / Total Capitalization ⁽¹⁾	57 %	46 %	49 %	50 %	30 %	47 %	70 %	52 %	50 %	39 %
2022										
Avg. Monthly Residential Rev. (\$)	149.75	145.85	145.48	152.65	152.18	175.67	135.38	154.74	151.37	205.92
Avg. Monthly Residential kWh	1,056.00	1,218.00	1,164.00	1,181.00	1,296.00	1,255.00	1,124.00	1,149.00	1,216.00	1,210.00
Avg. Residential Rev.(cents per kWh)	14.18	11.97	12.50	12.93	11.74	14.00	12.05	13.46	12.45	17.02
Times Interest Earned Ratio ⁽¹⁾	1.40	1.48	1.63	2.91	2.15	1.83	7.31	1.88	1.94	2.00
Equity / Assets ⁽¹⁾	48 %	35 %	42 %	44 %	26 %	37 %	57 %	46 %	44 %	33 %
Equity / Total Capitalization ⁽¹⁾	55 %	46 %	52 %	49 %	35 %	43 %	64 %	54 %	51 %	37 %
2021										
Avg. Monthly Residential Rev. (\$)	146.47	136.42	140.02	140.96	134.59	168.29	128.58	128.62	137.13	180.61
Avg. Monthly Residential kWh	1,029.00	1,217.00	1,138.00	1,177.00	1,251.00	1,223.00	1,088.00	1,174.00	1,208.00	1,212.00
Avg. Residential Rev.(cents per kWh)	14.24	11.21	12.30	11.97	10.76	13.76	11.82	10.96	11.35	14.90
Times Interest Earned Ratio ⁽¹⁾	2.93	2.26	2.21	3.58	2.39	3.92	5.32	1.58	3.26	1.16
Equity / Assets ⁽¹⁾	55 %	40 %	46 %	45 %	31 %	40 %	51 %	44 %	45 %	33 %
Equity / Total Capitalization ⁽¹⁾	61 %	52 %	56 %	51 %	39 %	45 %	60 %	53 %	58 %	38 %

Table 1 (Continued)

	Excelsior	Flint	Grady	GreyStone	Habersham	Hart	Irwin	Jackson	Jefferson	Little Ocmulgee
2023										
Avg. Monthly Residential Rev. (\$)	148.37	161.68	160.67	137.09	138.54	126.64	165.16	136.69	142.44	134.27
Avg. Monthly Residential kWh	1,124.00	1,198.00	1,083.00	1,145.00	1,006.00	1,032.00	1,001.00	1,141.00	1,058.00	947.00
Avg. Residential Rev.(cents per kWh)	13.20	13.50	14.84	11.98	13.77	12.27	16.51	11.98	13.47	14.18
Times Interest Earned Ratio ⁽¹⁾	3.00	2.48	4.36	2.42	3.51	3.68	1.74	3.90	4.00	1.89
Equity / Assets ⁽¹⁾	49 %	33 %	51 %	42 %	32 %	51 %	25 %	45 %	36 %	41 %
Equity / Total Capitalization ⁽¹⁾	62 %	40 %	58 %	48 %	40 %	64 %	30 %	53 %	43 %	50 %
2022										
Avg. Monthly Residential Rev. (\$)	154.99	168.19	164.74	129.87	139.80	164.11	156.48	149.77	143.45	134.15
Avg. Monthly Residential kWh	1,204.00	1,268.00	1,088.00	1,189.00	1,078.00	1,170.00	1,026.00	1,232.00	1,137.00	949.00
Avg. Residential Rev.(cents per kWh)	12.87	13.27	15.15	10.92	12.97	14.02	15.25	12.16	12.62	14.14
Times Interest Earned Ratio ⁽¹⁾	3.01	2.30	5.98	2.61	0.69	8.68	0.09	3.38	1.53	2.01
Equity / Assets ⁽¹⁾	52 %	35 %	51 %	47 %	31 %	53 %	29 %	45 %	33 %	40 %
Equity / Total Capitalization ⁽¹⁾	65 %	43 %	62 %	55 %	39 %	66 %	31 %	53 %	41 %	48 %
2021										
Avg. Monthly Residential Rev. (\$)	129.06	160.79	150.70	123.24	132.84	142.60	146.91	133.89	136.92	133.56
Avg. Monthly Residential kWh	1,194.00	1,235.00	1,092.00	1,186.00	1,032.00	1,133.00	1,037.00	1,182.00	1,099.00	955.00
Avg. Residential Rev.(cents per kWh)	10.81	13.02	13.80	10.39	12.87	12.59	14.17	11.33	12.46	13.99
Times Interest Earned Ratio ⁽¹⁾	2.74	2.74	3.44	3.88	2.78	6.44	2.15	3.10	2.03	2.16
Equity / Assets ⁽¹⁾	53 %	38 %	48 %	49 %	36 %	50 %	37 %	46 %	34 %	41 %
Equity / Total Capitalization ⁽¹⁾	67 %	46 %	58 %	55 %	46 %	65 %	40 %	53 %	43 %	47 %

Footnotes:

(1) Times Interest Earned and Equity ratios were calculated from information contained on each Member's RUS Form 7, or similar form provided to another lender, and were not independently verified by each respective Member.

Table 1 (Continued)

	Middle Georgia	Mitchell	Ocmulgee	Oconee	Okefenoke	Planters	Rayle	Satilla	Sawnee	Slash Pine
2023										
Avg. Monthly Residential Rev. (\$)	194.34	174.68	138.18	176.03	160.19	157.32	149.87	149.79	141.92	156.91
Avg. Monthly Residential kWh	1,149.00	1,119.00	926.00	1,115.00	1,149.00	1,099.00	1,034.00	1,134.00	1,128.00	1,040.00
Avg. Residential Rev.(cents per kWh)	16.92	15.62	14.92	15.79	13.95	14.32	14.50	13.21	12.58	15.08
Times Interest Earned Ratio ⁽¹⁾	2.73	3.45	4.69	4.20	2.24	4.82	2.52	2.43	3.94	7.01
Equity / Assets ⁽¹⁾	27 %	45 %	54 %	44 %	35 %	47 %	41 %	35 %	34 %	45 %
Equity / Total Capitalization ⁽¹⁾	30 %	54 %	63 %	54 %	40 %	56 %	49 %	41 %	46 %	52 %
2022										
Avg. Monthly Residential Rev. (\$)	175.23	178.39	132.19	160.38	162.32	157.32	155.92	156.80	142.17	142.62
Avg. Monthly Residential kWh	1,162.00	1,136.00	941.00	1,136.00	1,196.00	1,165.00	1,109.00	1,165.00	1,180.00	1,062.00
Avg. Residential Rev.(cents per kWh)	15.09	15.70	14.05	14.12	13.57	13.50	14.06	13.46	12.05	13.43
Times Interest Earned Ratio ⁽¹⁾	1.64	2.48	(1.59)	0.81	1.82	3.79	2.79	1.76	3.92	1.12
Equity / Assets ⁽¹⁾	31 %	47 %	66 %	41 %	35 %	46 %	41 %	39 %	33 %	42 %
Equity / Total Capitalization ⁽¹⁾	40 %	58 %	76 %	54 %	40 %	56 %	46 %	46 %	46 %	50 %
2021										
Avg. Monthly Residential Rev. (\$)	163.64	169.26	124.08	155.63	145.84	157.36	140.49	140.92	138.97	140.20
Avg. Monthly Residential kWh	1,183.00	1,147.00	961.00	1,153.00	1,164.00	1,187.00	1,064.00	1,195.00	1,164.00	1,084.00
Avg. Residential Rev.(cents per kWh)	13.84	14.75	12.91	13.49	12.53	13.26	13.21	11.79	11.94	12.93
Times Interest Earned Ratio ⁽¹⁾	1.77	2.32	7.05	2.10	2.45	4.16	2.85	2.59	4.03	3.32
Equity / Assets ⁽¹⁾	42 %	48 %	72 %	43 %	37 %	48 %	41 %	45 %	33 %	44 %
Equity / Total Capitalization ⁽¹⁾	47 %	59 %	83 %	53 %	42 %	58 %	46 %	55 %	47 %	52 %

Table 1 (Continued)

	Snapping Shoals	Southern Rivers	Sumter	Three Notch	Tri County	Upson	Walton	Washington	MEMBER WTD AVG.
2023									
Avg. Monthly Residential Rev. (\$)	151.60	193.04	172.63	142.71	161.50	145.07	157.12	137.96	146.00
Avg. Monthly Residential kWh	1,236.00	1,191.00	1,250.00	877.00	1,106.00	1,072.00	1,176.00	945.00	1,131
Avg. Residential Rev.(cents per kWh)	12.27	16.20	13.81	16.30	14.60	13.54	13.36	14.59	12.91
Times Interest Earned Ratio ⁽¹⁾	2.22	3.41	2.96	5.55	1.58	17.89	4.76	1.89	3.69
Equity / Assets ⁽¹⁾	32 %	33 %	48 %	54 %	27 %	69 %	41 %	34 %	42 %
Equity / Total Capitalization ⁽¹⁾	49 %	37 %	53 %	58 %	32 %	77 %	61 %	37 %	51 %
2022									
Avg. Monthly Residential Rev. (\$)	154.72	186.47	169.99	130.71	170.89	140.26	158.61	151.45	150.85
Avg. Monthly Residential kWh	1,299.00	1,262.00	1,268.00	878.00	1,176.00	1,075.00	1,266.00	1,042.00	1,190
Avg. Residential Rev.(cents per kWh)	11.91	14.80	13.40	14.90	14.54	13.04	12.52	14.54	12.67
Times Interest Earned Ratio ⁽¹⁾	1.96	1.61	2.70	3.08	1.54	1.50	2.48	1.61	3.04
Equity / Assets ⁽¹⁾	33 %	33 %	48 %	49 %	28 %	66 %	41 %	40 %	42 %
Equity / Total Capitalization ⁽¹⁾	51 %	39 %	56 %	52 %	32 %	75 %	61 %	44 %	51 %
2021									
Avg. Monthly Residential Rev. (\$)	135.59	162.03	166.91	125.36	151.74	119.39	145.74	129.41	138.94
Avg. Monthly Residential kWh	1,289.00	1,216.00	1,281.00	891.00	1,142.00	1,078.00	1,219.00	1,016.00	1,169
Avg. Residential Rev.(cents per kWh)	10.52	13.30	13.03	14.10	13.28	11.08	11.96	12.74	11.88
Times Interest Earned Ratio ⁽¹⁾	2.19	1.88	2.47	1.74	2.49	6.27	2.83	1.79	3.22
Equity / Assets ⁽¹⁾	33 %	36 %	48 %	50 %	33 %	68 %	42 %	49 %	43 %
Equity / Total Capitalization ⁽¹⁾	51 %	42 %	54 %	54 %	37 %	75 %	63 %	53 %	53 %

Footnotes:

(1) Times Interest Earned and Equity ratios were calculated from information contained on each Member's RUS Form 7, or similar form provided to another lender, and were not independently verified by each respective Member.

**FINANCIAL AND STATISTICAL INFORMATION FOR THE
38 MEMBERS OF OGLETHORPE POWER CORPORATION**

**Table 2
AVERAGE NUMBER OF CONSUMERS SERVED BY EACH MEMBER**

	<u>Altamaha</u>	<u>Amicalola</u>	<u>Canoochee</u>	<u>Carroll</u>	<u>Central Georgia</u>	<u>Coastal</u>	<u>Cobb</u>	<u>Colquitt</u>	<u>Coweta- Fayette</u>	<u>Diverse</u>
2023										
Residential Service	19,464	49,088	23,330	52,344	59,079	19,782	197,574	64,989	81,525	31,818
Commercial & Industrial	1,931	5,915	413	2,684	5,575	2,983	17,814	3,813	6,610	4,307
Other	277	3	835	397	419	134	5,495	3,344	1,016	1,057
<u>Total Consumers Served</u>	<u>21,672</u>	<u>55,006</u>	<u>24,578</u>	<u>55,425</u>	<u>65,073</u>	<u>22,899</u>	<u>220,883</u>	<u>72,146</u>	<u>89,151</u>	<u>37,182</u>
2022										
Residential Service	19,261	47,831	22,664	51,513	57,588	19,144	195,037	64,161	80,242	31,305
Commercial & Industrial	1,906	5,821	398	2,642	5,642	2,921	17,625	3,781	6,551	4,330
Other	272	5	827	392	398	135	5,449	3,273	987	1,054
<u>Total Consumers Served</u>	<u>21,439</u>	<u>53,657</u>	<u>23,889</u>	<u>54,547</u>	<u>63,628</u>	<u>22,200</u>	<u>218,111</u>	<u>71,215</u>	<u>87,780</u>	<u>36,689</u>
2021										
Residential Service	19,096	46,675	21,956	50,451	55,732	18,634	192,756	63,154	78,622	30,743
Commercial & Industrial	1,897	5,459	390	2,603	5,579	2,826	17,388	3,714	6,452	4,305
Other	262	5	808	385	383	136	5,430	3,237	951	1,032
<u>Total Consumers Served</u>	<u>21,255</u>	<u>52,139</u>	<u>23,154</u>	<u>53,439</u>	<u>61,694</u>	<u>21,596</u>	<u>215,574</u>	<u>70,105</u>	<u>86,025</u>	<u>36,080</u>

Table 2 (Continued)

	Excelsior	Flint	Grady	GreyStone	Habersham	Hart	Irwin	Jackson	Jefferson	Little Ocmulgee
2023										
Residential Service	23,085	81,740	19,156	134,757	34,490	29,621	10,886	232,048	34,249	11,271
Commercial & Industrial	1,542	11,585	501	10,796	2,606	9,194	247	19,512	1,927	161
Other	486	1,196	732	1,994	13	11	1,684	5,507	457	461
Total Consumers Served	25,113	94,521	20,389	147,547	37,109	38,826	12,817	257,067	36,633	11,893
2022										
Residential Service	22,630	79,919	19,032	131,489	33,899	29,200	10,863	225,116	33,694	11,202
Commercial & Industrial	1,524	11,369	497	10,742	2,566	8,965	242	19,030	1,889	157
Other	473	1,194	717	1,965	9	20	1,660	5,360	448	461
Total Consumers Served	24,627	92,482	20,246	144,196	36,474	38,185	12,765	249,506	36,031	11,820
2021										
Residential Service	22,172	78,564	18,899	128,478	33,222	28,879	10,789	219,455	33,101	11,095
Commercial & Industrial	1,488	11,154	491	10,699	2,552	8,821	238	18,591	1,860	152
Other	460	1,185	704	1,969	8	11	1,652	5,212	446	461
Total Consumers Served	24,120	90,903	20,094	141,146	35,782	37,711	12,679	243,258	35,407	11,708

Table 2 (Continued)

	Middle Georgia	Mitchell	Ocmulgee	Oconee	Okefenoke	Planters	Rayle	Satilla	Sawnee	Slash Pine
2023										
Residential Service	5,303	21,296	11,445	10,592	38,023	16,290	16,267	53,451	177,427	8,656
Commercial & Industrial	1,864	1,206	719	2,403	2,341	711	3,377	2,905	18,029	617
Other	1,305	3,129	736	198	471	1,063	-	2,601	2,059	264
Total Consumers Served	8,472	25,631	12,900	13,193	40,835	18,064	19,644	58,957	197,515	9,537
2022										
Residential Service	5,281	21,209	11,368	10,575	37,023	16,151	16,118	52,861	174,430	8,557
Commercial & Industrial	1,826	1,209	710	2,329	2,306	705	3,248	2,890	17,754	618
Other	1,282	3,098	720	196	455	1,036	-	2,567	2,041	243
Total Consumers Served	8,389	25,516	12,798	13,100	39,784	17,892	19,366	58,318	194,225	9,418
2021										
Residential Service	5,186	21,157	11,212	10,544	36,122	16,008	15,949	52,301	171,185	8,420
Commercial & Industrial	1,805	1,195	710	2,246	2,307	697	3,134	2,833	17,512	616
Other	1,252	3,055	709	195	439	1,020	-	2,546	2,040	226
Total Consumers Served	8,243	25,407	12,631	12,985	38,868	17,725	19,083	57,680	190,737	9,262

Table 2 (Continued)

	Snapping Shoals	Southern Rivers	Sumter	Three Notch	Tri- County	Upson	Walton	Washington	MEMBER TOTAL
<u>2023</u>									
Residential Service	101,193	20,055	14,963	13,719	20,777	8,861	129,144	15,091	1,892,849
Commercial & Industrial	4,392	1,164	5,275	503	2,198	528	8,864	953	168,165
Other	1,387	21	916	1,064	-	144	1,653	167	42,696
Total Consumers Served	106,972	21,240	21,154	15,286	22,975	9,533	139,661	16,211	2,103,710
<u>2022</u>									
Residential Service	99,814	19,691	14,921	13,881	20,547	8,790	127,193	14,981	1,859,181
Commercial & Industrial	4,358	1,145	5,234	489	2,171	544	8,674	946	165,754
Other	1,778	21	891	1,048	-	143	1,485	162	42,265
Total Consumers Served	105,950	20,857	21,046	15,418	22,718	9,477	137,352	16,089	2,067,200
<u>2021</u>									
Residential Service	98,760	19,274	14,838	13,607	20,208	8,666	124,848	15,118	1,825,876
Commercial & Industrial	4,279	1,102	5,161	482	2,149	552	8,524	678	162,641
Other	1,379	21	860	1,027	-	137	1,482	143	41,268
Total Consumers Served	104,418	20,397	20,859	15,116	22,357	9,355	134,854	15,939	2,029,785

**FINANCIAL AND STATISTICAL INFORMATION FOR THE
38 MEMBERS OF OGLETHORPE POWER CORPORATION**

**Table 3
ANNUAL MWh SALES BY CONSUMER CLASS OF EACH MEMBER**

	<u>Altamaha</u>	<u>Amicalola</u>	<u>Canoochee</u>	<u>Carroll</u>	<u>Central Georgia</u>	<u>Coastal</u>	<u>Cobb</u>	<u>Colquitt</u>	<u>Coweta- Fayette</u>	<u>Diverse</u>
2023										
Residential Service	230,703	687,463	308,924	716,097	863,405	280,062	2,533,635	878,512	1,158,515	450,299
Commercial & Industrial	332,070	122,890	138,131	399,495	490,792	260,356	1,132,141	298,908	475,349	229,745
Other	9,419	77	15,610	6,246	3,950	2,309	232,362	99,431	5,989	42,216
<u>Total MWh Sales</u>	<u>572,192</u>	<u>810,430</u>	<u>462,665</u>	<u>1,121,838</u>	<u>1,358,147</u>	<u>542,726</u>	<u>3,898,138</u>	<u>1,276,850</u>	<u>1,639,853</u>	<u>722,260</u>
2022										
Residential Service	244,092	699,329	316,540	729,990	895,626	288,254	2,630,027	884,946	1,170,511	454,391
Commercial & Industrial	274,337	122,842	141,079	403,565	495,162	264,429	1,151,120	299,281	471,846	224,913
Other	10,396	86	17,517	6,175	3,736	2,369	239,232	95,730	6,432	45,353
<u>Total MWh Sales</u>	<u>528,825</u>	<u>822,257</u>	<u>475,135</u>	<u>1,139,730</u>	<u>1,394,525</u>	<u>555,051</u>	<u>4,020,380</u>	<u>1,279,957</u>	<u>1,648,789</u>	<u>724,656</u>
2021										
Residential Service	235,684	681,433	299,920	712,650	836,527	273,499	2,516,660	889,519	1,139,558	447,099
Commercial & Industrial	176,729	117,260	134,211	412,211	458,238	247,070	1,131,685	286,853	462,301	206,192
Other	7,264	92	15,276	5,777	3,622	2,066	230,838	74,793	6,721	36,030
<u>Total MWh Sales</u>	<u>419,677</u>	<u>798,784</u>	<u>449,408</u>	<u>1,130,638</u>	<u>1,298,387</u>	<u>522,636</u>	<u>3,879,183</u>	<u>1,251,165</u>	<u>1,608,580</u>	<u>689,321</u>

Table 3 (Continued)

	<u>Excelsior</u>	<u>Flint</u>	<u>Grady</u>	<u>GreyStone</u>	<u>Habersham</u>	<u>Hart</u>	<u>Irwin</u>	<u>Jackson</u>	<u>Jefferson</u>	<u>Little Ocmulgee</u>
2023										
Residential Service	311,291	1,174,798	248,881	1,850,772	416,315	366,788	130,702	3,178,004	434,662	128,097
Commercial & Industrial	159,587	640,511	35,853	1,054,055	101,521	214,842	28,682	2,063,517	143,401	48,747
Other	4,292	42,645	19,599	10,988	120	698	22,088	306,631	18,955	6,374
Total MWh Sales	475,170	1,857,953	304,333	2,915,815	517,957	582,328	181,471	5,548,151	597,018	183,217
2022										
Residential Service	327,084	1,215,797	248,393	1,876,572	438,519	410,046	133,760	3,327,794	459,678	127,566
Commercial & Industrial	73,097	639,544	40,630	1,063,758	104,136	217,001	31,948	2,066,222	160,625	52,906
Other	5,517	47,178	17,834	10,704	123	979	30,170	314,111	21,150	6,709
Total MWh Sales	405,698	1,902,519	306,856	2,951,033	542,778	628,027	195,878	5,708,128	641,452	187,181
2021										
Residential Service	317,664	1,164,173	247,692	1,829,269	411,491	392,546	134,254	3,113,308	436,444	127,152
Commercial & Industrial	69,517	612,517	41,145	1,042,924	99,702	205,795	30,989	2,013,130	138,498	48,226
Other	4,191	38,189	14,748	11,226	47	643	16,645	304,339	18,232	4,137
Total MWh Sales	391,372	1,814,879	303,585	2,883,418	511,239	598,984	181,888	5,430,778	593,174	179,515

Table 3 (Continued)

	Middle Georgia	Mitchell	Ocmulgee	Oconee	Okefenoke	Planters	Rayle	Satilla	Sawnee	Slash Pine
2023										
Residential Service	73,099	285,847	127,237	141,738	524,116	214,750	201,779	727,488	2,401,600	108,066
Commercial & Industrial	46,915	78,523	44,043	97,779	100,060	32,905	68,493	330,284	999,686	70,923
Other	22,667	75,457	10,417	6,121	16,734	20,369	-	38,714	181,589	4,677
Total MWh Sales	142,681	439,826	181,698	245,638	640,910	268,023	270,272	1,096,486	3,582,875	183,666
2022										
Residential Service	73,611	289,178	128,314	144,165	531,475	225,872	214,462	739,024	2,469,224	109,029
Commercial & Industrial	46,902	77,104	44,571	99,634	85,609	34,800	72,737	329,376	1,018,679	71,496
Other	29,814	74,645	11,543	6,530	17,088	26,526	-	44,921	185,155	5,126
Total MWh Sales	150,327	440,927	184,428	250,328	634,171	287,198	287,199	1,113,321	3,673,058	185,651
2021										
Residential Service	73,594	291,274	129,348	145,920	504,382	227,976	203,603	750,190	2,390,472	109,569
Commercial & Industrial	42,771	75,326	46,076	105,309	80,072	34,091	67,885	325,764	1,009,171	72,678
Other	14,370	50,154	6,789	4,292	16,060	20,083	-	34,216	182,526	3,932
Total MWh Sales	130,736	416,754	182,214	255,521	600,514	282,150	271,487	1,110,170	3,582,168	186,179

Table 3 (Continued)

	Snapping Shoals	Southern Rivers	Sumter	Three Notch	Tri- County	Upson	Walton	Washington	MEMBER TOTAL
2023									
Residential Service	1,500,882	286,668	224,423	144,311	275,830	113,967	1,822,039	171,180	25,692,944
Commercial & Industrial	459,133	58,048	93,609	29,045	106,392	15,251	1,712,200	235,552	12,949,435
Other	17,112	4,712	40,899	52,673	-	3,078	61,550	7,170	1,413,937
Total MWh Sales	1,977,128	349,429	358,931	226,028	382,222	132,297	3,595,789	413,903	40,056,315
2022									
Residential Service	1,556,491	298,307	227,101	146,333	289,840	113,432	1,932,954	187,259	26,554,983
Commercial & Industrial	476,707	58,221	90,670	29,518	106,364	16,569	1,382,244	168,867	12,508,511
Other	17,779	4,627	44,380	47,562	-	3,051	58,182	7,422	1,465,849
Total MWh Sales	2,050,978	361,155	362,151	223,413	396,204	133,052	3,373,380	363,548	40,529,342
2021									
Residential Service	1,527,814	281,221	228,111	145,484	277,007	112,083	1,826,312	184,299	25,615,201
Commercial & Industrial	461,786	55,928	87,885	28,703	102,432	16,831	938,130	163,586	11,649,614
Other	18,286	4,501	29,817	34,381	-	2,572	55,660	5,311	1,277,828
Total MWh Sales	2,007,886	341,650	345,813	208,568	379,438	131,486	2,820,102	353,196	38,542,643

**FINANCIAL AND STATISTICAL INFORMATION FOR THE
38 MEMBERS OF OGLETHORPE POWER CORPORATION**

**Table 4
ANNUAL REVENUES BY CONSUMER CLASS OF EACH MEMBER**

	Altamaha	Amicalola	Canoochee	Carroll	Central Georgia	Coastal	Cobb	Colquitt	Coweta- Fayette	Diverse
2023										
Residential Service	\$35,762,142	\$82,491,698	\$40,770,490	\$97,149,430	\$105,620,018	\$39,623,478	\$294,316,938	\$111,152,711	\$135,259,470	\$79,280,116
Commercial & Industrial	27,862,481	16,432,964	12,679,496	36,700,864	41,527,694	24,315,801	111,500,385	31,436,044	47,473,258	25,560,239
Other	1,341,200	25,635	2,221,408	1,093,341	1,063,497	437,782	23,647,004	12,453,621	2,150,891	7,167,747
Total Electric Sales	\$64,965,823	\$98,950,297	\$55,671,394	\$134,943,635	\$148,211,209	\$64,377,061	\$429,464,327	\$155,042,376	\$184,883,619	\$112,008,102
Other Operating Revenue	1,124,153	5,094,009	11,439,543	7,193,081	11,078,054	2,576,356	10,091,160	4,072,321	5,715,266	2,408,646
Total Operating Revenue	\$66,089,976	\$104,044,306	\$67,110,937	\$142,136,716	\$159,289,263	\$66,953,417	\$439,555,487	\$159,114,697	\$190,598,885	\$114,416,748
2022										
Residential Service	\$34,611,328	\$83,713,185	\$39,565,688	\$94,360,649	\$105,164,396	\$40,356,183	\$316,853,414	\$119,140,699	\$145,755,946	\$77,356,082
Commercial & Industrial	23,073,256	16,467,533	11,910,805	34,092,521	42,300,137	25,410,283	115,030,381	32,065,097	50,336,931	24,590,702
Other	1,311,581	27,415	2,342,584	1,053,490	958,715	459,692	23,678,374	12,610,926	2,119,531	7,520,986
Total Electric Sales	\$58,996,165	\$100,208,133	\$53,819,077	\$129,506,660	\$148,423,248	\$66,226,158	\$455,562,169	\$163,816,722	\$198,212,408	\$109,467,770
Other Operating Revenue	2,041,601	9,174,772	14,004,902	8,831,980	14,287,025	834,566	10,211,711	4,051,932	10,014,298	1,949,985
Total Operating Revenue	\$61,037,766	\$109,382,905	\$67,823,979	\$138,338,640	\$162,710,273	\$67,060,724	\$465,773,880	\$167,868,654	\$208,226,706	\$111,417,755
2021										
Residential Service	\$33,564,038	\$76,406,079	\$36,890,611	\$85,335,988	\$90,010,762	\$37,630,443	\$297,411,036	\$97,471,103	\$129,375,339	\$66,630,291
Commercial & Industrial	17,186,413	14,790,193	11,033,271	31,220,869	35,447,473	23,474,737	110,121,821	26,782,676	45,210,012	21,300,819
Other	913,432	27,940	2,019,448	948,985	903,728	397,225	22,320,434	8,379,370	2,041,411	4,806,178
Total Electric Sales	\$51,663,883	\$91,224,212	\$49,943,330	\$117,505,842	\$126,361,963	\$61,502,405	\$429,853,291	\$132,633,149	\$176,626,762	\$92,737,288
Other Operating Revenue	806,594	(46,600)	10,542,687	6,065,971	7,203,320	866,251	9,226,399	3,442,407	3,246,149	2,973,705
Total Operating Revenue	\$52,470,477	\$91,177,612	\$60,486,017	\$123,571,813	\$133,565,283	\$62,368,656	\$439,079,690	\$136,075,556	\$179,872,911	\$95,710,993

Table 4 (Continued)

	Excelsior	Flint	Grady	GreyStone	Habersham	Hart	Irwin	Jackson	Jefferson	Little Ocmulgee
2023										
Residential Service	\$41,102,343	\$158,591,838	\$36,934,267	\$221,691,038	\$57,340,008	\$45,016,099	\$21,574,801	\$380,615,260	\$58,540,782	\$18,160,026
Commercial & Industrial	13,348,950	67,365,532	4,321,100	113,442,688	12,156,757	24,654,964	4,182,560	205,956,203	14,282,740	4,666,830
Other	983,666	6,407,242	3,075,283	3,310,989	33,439	69,541	4,969,962	39,159,091	3,097,913	980,383
Total Electric Sales	\$55,434,959	\$232,364,612	\$44,330,650	\$338,444,715	\$69,530,204	\$69,740,604	\$30,727,323	\$625,730,554	\$75,921,435	\$23,807,239
Other Operating Revenue	(632,402)	1,831,050	1,410,966	(10,799,778)	6,118,078	3,358,750	2,095,569	(10,627,056)	2,677,619	(164,905)
Total Operating Revenue	\$54,802,557	\$234,195,662	\$45,741,616	\$327,644,937	\$75,648,282	\$73,099,354	\$32,822,892	\$615,103,498	\$78,599,054	\$23,642,334
2022										
Residential Service	\$42,090,017	\$161,300,664	\$37,624,910	\$204,914,449	\$56,868,706	\$57,503,106	\$20,397,592	\$404,591,448	\$57,999,341	\$18,032,789
Commercial & Industrial	9,518,833	69,360,175	4,854,173	100,296,904	12,188,976	28,967,356	4,043,564	207,540,163	14,543,778	5,043,049
Other	1,170,485	6,853,394	2,960,373	3,239,532	29,316	109,410	4,918,654	40,013,617	3,151,557	1,016,363
Total Electric Sales	\$52,779,335	\$237,514,233	\$45,439,456	\$308,450,885	\$69,086,998	\$86,579,872	\$29,359,810	\$652,145,228	\$75,694,676	\$24,092,201
Other Operating Revenue	4,726,028	14,170,904	2,079,685	22,487,564	6,413,431	2,747,570	59,733	9,912,071	2,456,524	1,006,852
Total Operating Revenue	\$57,505,363	\$251,685,137	\$47,519,141	\$330,938,449	\$75,500,429	\$89,327,442	\$29,419,543	\$662,057,299	\$78,151,200	\$25,099,053
2021										
Residential Service	\$34,338,592	\$151,587,175	\$34,177,652	\$189,997,776	\$52,957,313	\$49,418,392	\$19,019,786	\$352,599,873	\$54,384,738	\$17,782,609
Commercial & Industrial	7,697,465	63,358,835	4,310,320	96,332,535	11,482,430	24,691,411	3,619,982	191,353,853	13,194,552	4,754,418
Other	773,208	5,557,184	2,368,854	3,157,114	12,836	69,919	3,022,144	35,916,869	2,817,874	720,184
Total Electric Sales	\$42,809,265	\$220,503,194	\$40,856,826	\$289,487,425	\$64,452,579	\$74,179,722	\$25,661,912	\$579,870,595	\$70,397,164	\$23,257,211
Other Operating Revenue	293,183	7,963,214	924,099	17,549,540	4,099,002	2,821,911	2,874,120	3,995,007	2,789,387	39,693
Total Operating Revenue	\$43,102,448	\$228,466,408	\$41,780,925	\$307,036,965	\$68,551,581	\$77,001,633	\$28,536,032	\$583,865,602	\$73,186,551	\$23,296,904

Table 4 (Continued)

	Middle Georgia	Mitchell	Ocmulgee	Oconee	Okefenoke	Planters	Rayle	Satilla	Sawnee	Slash Pine
2023										
Residential Service	\$12,366,856	\$44,639,679	\$18,978,001	\$22,373,871	\$73,088,751	\$30,752,844	\$29,254,978	\$96,076,792	\$302,161,217	\$16,298,143
Commercial & Industrial	7,718,984	9,902,952	5,340,440	10,717,348	10,547,810	3,717,803	9,277,771	24,572,192	106,739,374	8,441,072
Other	4,444,673	10,907,602	1,626,265	855,029	2,215,698	3,334,794	-	6,429,643	19,294,785	830,318
Total Electric Sales	\$24,530,513	\$65,450,233	\$25,944,706	\$33,946,248	\$85,852,259	\$37,805,441	\$38,532,749	\$127,078,627	\$428,195,376	\$25,569,533
Other Operating Revenue	1,897,899	1,857,113	1,836,384	1,601,344	871,768	(330,142)	(759,534)	8,222,235	13,299,157	369,411
Total Operating Revenue	\$26,428,412	\$67,307,346	\$27,781,090	\$35,547,592	\$86,724,027	\$37,475,299	\$37,773,215	\$135,300,862	\$441,494,533	\$25,938,944
2022										
Residential Service	\$11,104,763	\$45,401,693	\$18,032,704	\$20,352,223	\$72,116,307	\$30,491,126	\$30,157,737	\$99,461,450	\$297,588,972	\$14,644,320
Commercial & Industrial	6,840,960	10,084,219	5,548,168	9,838,058	9,904,549	3,733,348	9,823,738	26,411,702	104,525,418	7,426,830
Other	5,041,661	11,083,290	2,012,549	814,343	2,201,449	3,932,479	-	7,242,820	19,405,620	736,293
Total Electric Sales	\$22,987,384	\$66,569,202	\$25,593,421	\$31,004,624	\$84,222,305	\$38,156,953	\$39,981,475	\$133,115,972	\$421,520,010	\$22,807,443
Other Operating Revenue	936,013	3,123,560	680,967	2,280,664	1,380,719	2,109,933	1,293,060	4,596,975	30,823,506	816,990
Total Operating Revenue	\$23,923,397	\$69,692,762	\$26,274,388	\$33,285,288	\$85,603,024	\$40,266,886	\$41,274,535	\$137,712,947	\$452,343,516	\$23,624,433
2021										
Residential Service	\$10,183,787	\$42,971,237	\$16,694,199	\$19,691,458	\$63,214,287	\$30,227,476	\$26,888,343	\$88,440,099	\$285,469,555	\$14,165,755
Commercial & Industrial	5,823,549	9,285,528	4,871,181	9,886,366	8,221,611	3,573,505	8,565,018	23,248,861	102,551,294	7,189,949
Other	2,596,794	7,439,203	1,128,389	565,585	1,894,492	3,114,719	-	5,121,754	18,485,060	577,905
Total Electric Sales	\$18,604,130	\$59,695,968	\$22,693,769	\$30,143,409	\$73,330,390	\$36,915,700	\$35,453,361	\$116,810,714	\$406,505,909	\$21,933,609
Other Operating Revenue	1,174,087	1,351,327	735,654	(311,332)	2,252,283	(1,858,873)	335,510	3,466,205	(6,916,291)	130,123
Total Operating Revenue	\$19,778,217	\$61,047,295	\$23,429,423	\$29,832,077	\$75,582,673	\$35,056,827	\$35,788,871	\$120,276,919	\$399,589,618	\$22,063,732

Table 4 (Continued)

	Snapping Shoals	Southern Rivers	Sumter	Three Notch	Tri- County	Upson	Walton	Washington	MEMBER TOTAL
2023									
Residential Service	\$184,093,651	\$46,456,273	\$30,996,946	\$23,493,553	\$40,265,983	\$15,425,757	\$243,493,771	\$24,983,699	\$3,316,193,718
Commercial & Industrial	44,268,515	8,173,622	13,794,336	4,949,430	11,696,846	2,031,273	119,113,060	18,732,486	1,259,602,864
Other	3,495,810	653,604	6,235,694	10,193,223	-	470,180	9,264,205	1,002,445	194,943,603
Total Electric Sales	\$231,857,976	\$55,283,499	\$51,026,976	\$38,636,206	\$51,962,829	\$17,927,210	\$371,871,036	\$44,718,630	\$4,770,740,185
Other Operating Revenue	(2,512,914)	3,826,462	1,317,563	810,249	1,925,688	846,434	(8,343,420)	3,142,408	85,938,585
Total Operating Revenue	\$229,345,062	\$59,109,961	\$52,344,539	\$39,446,455	\$53,888,517	\$18,773,644	\$363,527,616	\$47,861,038	\$4,856,678,770
2022									
Residential Service	\$185,317,977	\$44,062,102	\$30,436,922	\$21,772,179	\$42,135,551	\$14,794,261	\$242,083,316	\$27,226,024	\$3,365,380,219
Commercial & Industrial	43,866,960	7,455,565	13,036,283	4,491,619	12,559,026	2,078,749	102,853,775	17,431,178	1,229,544,762
Other	3,442,986	551,577	6,418,361	8,748,557	-	433,667	8,626,990	1,060,224	197,298,861
Total Electric Sales	\$232,627,923	\$52,069,244	\$49,891,566	\$35,012,355	\$54,694,577	\$17,306,677	\$353,564,081	\$45,717,426	\$4,792,223,842
Other Operating Revenue	28,871,248	1,679,249	3,125,268	693,050	1,572,169	657,079	23,213,987	1,302,429	250,620,000
Total Operating Revenue	\$261,499,171	\$53,748,493	\$53,016,834	\$35,705,405	\$56,266,746	\$17,963,756	\$376,778,068	\$47,019,855	\$5,042,843,842
2021									
Residential Service	\$160,688,027	\$37,475,681	\$29,719,439	\$20,469,574	\$36,797,298	\$12,415,924	\$218,337,156	\$23,476,636	\$3,044,315,527
Commercial & Industrial	38,738,312	6,210,131	12,429,415	4,189,777	10,298,146	1,896,719	81,564,442	14,229,106	1,110,136,995
Other	3,398,833	442,143	4,673,254	6,820,441	-	325,447	8,052,283	727,268	162,537,907
Total Electric Sales	\$202,825,172	\$44,127,955	\$46,822,108	\$31,479,792	\$47,095,444	\$14,638,090	\$307,953,881	\$38,433,010	\$4,316,990,429
Other Operating Revenue	7,312,526	1,071,173	999,552	486,018	1,316,143	435,564	29,595,170	908,132	130,159,010
Total Operating Revenue	\$210,137,698	\$45,199,128	\$47,821,660	\$31,965,810	\$48,411,587	\$15,073,654	\$337,549,051	\$39,341,142	\$4,447,149,439

**FINANCIAL AND STATISTICAL INFORMATION FOR THE
38 MEMBERS OF OGLETHORPE POWER CORPORATION**

**Table 5
SUMMARY OF OPERATING RESULTS OF EACH MEMBER**

	Altamaha	Amicalola	Canoochee	Carroll	Central Georgia	Coastal	Cobb	Colquitt	Coweta- Fayette	Diverse
2023										
Operating Revenue & Patronage Capital	\$66,089,976	\$104,044,306	\$67,110,938	\$142,136,716	\$159,289,263	\$66,953,417	\$439,555,487	\$159,114,697	\$190,598,884	\$114,416,748
Depreciation and Amortization	4,788,353	8,160,471	6,776,058	11,130,818	9,681,035	5,145,614	35,584,293	12,042,286	13,487,567	10,148,628
Other Operating Expenses	50,145,915	90,838,055	54,806,918	101,027,080	136,418,487	52,032,709	385,441,724	132,072,796	165,906,458	93,909,433
Electric Operating Margin	\$11,155,708	\$5,045,780	\$5,527,962	\$29,978,818	\$13,189,741	\$9,775,094	\$18,529,470	\$14,999,615	\$11,204,859	\$10,358,687
Other Income	2,800,351	3,885,936	1,951,928	2,320,198	7,617,211	1,272,579	95,817,444	2,576,202	17,641,698	2,810,470
Gross Operating Margin	\$13,956,059	\$8,931,716	\$7,479,890	\$32,299,016	\$20,806,952	\$11,047,673	\$114,346,914	\$17,575,817	\$28,846,557	\$13,169,157
Interest on Long-term Debt	2,431,923	3,397,845	2,595,579	4,775,459	7,870,609	2,566,451	15,860,514	4,872,688	6,125,446	6,549,963
Other Deductions	492,269	725,946	9,325	12,796	4,188,325	176,753	1,288,626	673,745	1,121,960	27,780
Net Margins	\$11,031,867	\$4,807,925	\$4,874,986	\$27,510,761	\$8,748,018	\$8,304,469	\$97,197,774	\$12,029,384	\$21,599,151	\$6,591,414
2022										
Operating Revenue & Patronage Capital	\$61,037,766	\$109,382,905	\$67,823,979	\$138,338,640	\$162,710,273	\$67,060,725	\$465,773,880	\$167,868,654	\$208,226,706	\$111,417,755
Depreciation and Amortization	4,490,139	7,738,396	6,591,212	10,433,307	8,824,503	4,666,217	33,294,569	11,541,110	12,632,273	9,815,658
Other Operating Expenses	54,254,694	98,391,170	59,145,035	116,288,238	145,432,838	59,096,564	408,423,697	149,538,320	186,478,716	92,593,206
Electric Operating Margin	\$2,292,933	\$3,253,339	\$2,087,732	\$11,617,095	\$8,452,932	\$3,297,944	\$24,055,614	\$6,789,224	\$9,115,717	\$9,008,891
Other Income	541,960	1,623,473	1,373,440	714,489	4,187,305	1,354,906	101,704,719	2,327,475	2,077,264	2,411,574
Gross Operating Margin	\$2,834,893	\$4,876,812	\$3,461,172	\$12,331,584	\$12,640,237	\$4,652,850	\$125,760,333	\$9,116,699	\$11,192,981	\$11,420,465
Interest on Long-term Debt	1,913,496	3,192,160	2,118,093	4,229,043	5,208,630	2,538,089	17,074,533	4,854,707	5,502,620	5,622,166
Other Deductions	164,422	140,619	10,955	40,517	1,451,491	12,537	998,921	-	540,910	188,882
Net Margins	\$756,975	\$1,544,033	\$1,332,124	\$8,062,024	\$5,980,116	\$2,102,224	\$107,686,879	\$4,261,992	\$5,149,451	\$5,609,417
2021										
Operating Revenue & Patronage Capital	\$52,470,476	\$91,177,614	\$60,486,017	\$123,571,813	\$133,565,283	\$62,368,655	\$439,079,690	\$136,075,556	\$179,872,911	\$95,710,993
Depreciation and Amortization	4,357,572	7,267,588	6,025,422	9,984,048	8,364,722	4,393,308	32,333,041	10,890,404	11,929,991	9,843,373
Other Operating Expenses	44,159,823	83,054,400	50,956,279	100,092,448	116,046,167	49,419,240	373,298,742	119,968,126	158,706,395	81,093,870

Table 5 (Continued)

Electric Operating Margin	\$3,953,081	\$855,626	\$3,504,316	\$13,495,317	\$9,154,394	\$8,556,107	\$33,447,907	\$5,217,026	\$9,236,525	\$4,773,750
Other Income	1,112,678	5,622,541	1,152,763	987,606	2,876,507	1,083,982	69,247,915	2,040,411	6,560,069	1,698,945
Gross Operating Margin	\$5,065,759	\$6,478,167	\$4,657,079	\$14,482,923	\$12,030,901	\$9,640,089	\$102,695,822	\$7,257,437	\$15,796,594	\$6,472,695
Interest on Long-term Debt	1,715,240	2,852,304	2,102,589	4,042,744	4,916,054	2,455,293	19,164,118	4,583,870	4,641,091	5,577,757
Other Deductions	43,311	26,853	10,123	5,085	263,377	7,437	687,053	-	670,272	26,809
Net Margins	\$3,307,208	\$3,599,010	\$2,544,367	\$10,435,094	\$6,851,470	\$7,177,359	\$82,844,651	\$2,673,567	\$10,485,231	\$868,129

Table 5 (Continued)

	Excelsior	Flint	Grady	GreyStone	Habersham	Hart	Irwin	Jackson	Jefferson	Little Ocmulgee
2023										
Operating Revenue & Patronage Capital	\$54,802,552	\$234,195,662	\$45,741,615	\$327,644,936	\$75,648,282	\$73,099,354	\$32,822,892	\$615,103,498	\$78,599,054	\$23,642,334
Depreciation and Amortization	3,467,186	16,904,171	3,845,790	22,591,724	8,731,685	6,299,544	4,071,939	44,278,176	6,414,069	2,572,011
Other Operating Expenses	49,587,252	206,384,712	34,338,819	286,396,181	57,901,576	63,045,446	24,027,721	532,116,643	61,076,919	19,335,088
Electric Operating Margin	\$1,757,114	\$10,906,779	\$7,557,006	\$18,657,031	\$9,015,021	\$3,754,364	\$4,723,232	\$38,708,679	\$11,108,066	\$1,735,235
Other Income	2,557,140	8,441,927	3,918,997	10,911,096	4,746,990	5,110,774	1,547,497	28,113,368	1,307,826	348,079
Gross Operating Margin	\$4,314,254	\$19,348,706	\$11,476,003	\$29,568,127	\$13,762,011	\$8,865,138	\$6,270,729	\$66,822,047	\$12,415,892	\$2,083,314
Interest on Long-term Debt	1,439,449	7,280,949	2,597,909	12,044,450	3,726,060	2,411,669	3,324,518	17,099,954	3,039,589	1,100,000
Other Deductions	-	1,304,589	161,926	438,681	687,977	2,060	473,460	47,021	267,966	-
Net Margins	\$2,874,805	\$10,763,168	\$8,716,168	\$17,084,996	\$9,347,974	\$6,451,409	\$2,472,751	\$49,675,072	\$9,108,337	\$983,314
2022										
Operating Revenue & Patronage Capital	\$57,505,363	\$251,685,137	\$47,519,141	\$330,938,449	\$75,500,429	\$89,327,442	\$29,419,544	\$662,057,299	\$78,151,200	\$25,099,053
Depreciation and Amortization	3,270,383	16,241,278	3,670,698	21,559,980	7,466,653	5,976,089	3,486,809	40,768,375	6,129,635	2,494,794
Other Operating Expenses	52,801,777	222,177,485	38,185,470	293,437,428	68,759,893	70,389,573	26,362,733	588,992,605	69,005,654	21,352,580
Electric Operating Margin	\$1,433,203	\$13,266,374	\$5,662,973	\$15,941,041	(\$726,117)	\$12,961,780	(\$429,998)	\$32,296,319	\$3,015,911	\$1,251,679
Other Income	1,725,077	1,119,666	4,509,641	9,771,437	3,186,452	3,374,069	703,980	22,372,846	1,022,350	150,636
Gross Operating Margin	\$3,158,280	\$14,386,040	\$10,172,614	\$25,712,478	\$2,460,335	\$16,335,849	\$273,982	\$54,669,165	\$4,038,261	\$1,402,315
Interest on Long-term Debt	1,048,979	6,024,325	1,661,961	9,669,569	3,072,624	1,882,325	2,144,675	16,160,016	2,536,713	699,000
Other Deductions	-	511,394	228,306	440,510	345,797	2,583	87,851	20,678	150,940	-
Net Margins	\$2,109,301	\$7,850,321	\$8,282,347	\$15,602,399	(\$958,086)	\$14,450,941	(\$1,958,544)	\$38,488,471	\$1,350,608	\$703,315
2021										
Operating Revenue & Patronage Capital	\$43,102,448	\$228,466,408	\$41,780,925	\$307,036,964	\$68,551,581	\$77,001,634	\$28,536,032	\$583,865,602	\$73,185,551	\$23,296,905
Depreciation and Amortization	3,097,051	15,759,780	3,585,669	19,075,276	6,727,175	5,707,348	3,374,195	38,596,482	6,002,989	2,209,116
Other Operating Expenses	38,828,109	200,322,301	33,608,001	269,650,406	57,488,913	62,900,405	21,698,943	516,642,333	61,426,705	19,580,951
Electric Operating Margin	\$1,177,288	\$12,384,327	\$4,587,255	\$18,311,282	\$4,335,493	\$8,393,881	\$3,462,894	\$28,626,787	\$5,755,857	\$1,506,838
Other Income	1,565,650	1,637,405	801,223	19,912,039	2,477,289	4,069,883	538,075	17,854,839	(1,181,369)	657,113
Gross Operating Margin	\$2,742,938	\$14,021,732	\$5,388,478	\$38,223,321	\$6,812,782	\$12,463,764	\$4,000,969	\$46,481,626	\$4,574,488	\$2,163,951
Interest on Long-term Debt	1,000,159	4,958,399	1,521,747	9,832,261	2,354,627	1,935,557	1,835,611	14,992,742	2,218,962	1,000,000
Other Deductions	-	431,511	156,321	115,002	274,874	2,859	62,304	-	59,086	-
Net Margins	\$1,742,779	\$8,631,822	\$3,710,410	\$28,276,058	\$4,183,281	\$10,525,348	\$2,103,054	\$31,488,884	\$2,296,440	\$1,163,951

Table 5 (Continued)

	Middle Georgia	Mitchell	Ocmulgee	Oconee	Okefenoke	Planters	Rayle	Satilla	Sawnee	Slash Pine
2023										
Operating Revenue & Patronage Capital	\$26,428,412	\$67,307,346	\$27,781,090	\$35,547,592	\$86,724,027	\$37,475,300	\$37,773,215	\$135,300,859	\$441,494,534	\$25,938,943
Depreciation and Amortization	2,899,337	5,260,074	1,708,667	2,535,956	6,614,787	2,990,595	3,376,742	10,183,221	25,078,379	1,396,940
Other Operating Expenses	18,310,564	53,210,397	22,095,988	27,810,470	72,413,307	30,569,287	31,545,647	110,408,593	386,647,335	19,016,220
Electric Operating Margin	\$5,218,511	\$8,836,875	\$3,976,435	\$5,201,166	\$7,695,933	\$3,915,418	\$2,850,826	\$14,709,045	\$29,768,820	\$5,525,783
Other Income	1,390,423	2,574,202	1,041,523	1,232,143	2,128,816	2,045,285	1,486,523	5,782,176	13,872,073	1,383,454
Gross Operating Margin	\$6,608,934	\$11,411,077	\$5,017,958	\$6,433,309	\$9,824,749	\$5,960,703	\$4,337,349	\$20,491,221	\$43,640,893	\$6,909,237
Interest on Long-term Debt	2,212,369	3,239,347	1,065,178	1,431,628	4,220,431	1,233,310	1,651,368	7,909,424	11,045,183	973,398
Other Deductions	570,597	238,446	19,093	422,621	359,740	11,874	181,540	1,294,435	110,749	84,505
Net Margins	<u>\$3,825,968</u>	<u>\$7,933,284</u>	<u>\$3,933,687</u>	<u>\$4,579,060</u>	<u>\$5,244,578</u>	<u>\$4,715,519</u>	<u>\$2,504,441</u>	<u>\$11,287,362</u>	<u>\$32,484,961</u>	<u>\$5,851,334</u>
2022										
Operating Revenue & Patronage Capital	\$23,923,397	\$69,692,762	\$26,274,388	\$33,285,288	\$85,603,024	\$40,266,887	\$41,274,535	\$137,712,945	\$452,343,517	\$23,624,433
Depreciation and Amortization	2,020,033	5,001,400	1,651,204	2,463,029	6,242,402	2,804,453	3,080,493	8,373,385	23,317,019	1,300,451
Other Operating Expenses	20,433,253	59,252,431	25,318,028	30,459,546	74,076,344	34,836,609	34,818,923	123,067,403	396,832,069	20,944,391
Electric Operating Margin	\$1,470,111	\$5,438,931	(\$694,844)	\$362,713	\$5,284,278	\$2,625,825	\$3,375,119	\$6,272,157	\$32,194,429	\$1,379,591
Other Income	729,823	1,668,838	309,395	868,223	1,958,518	1,570,766	1,103,661	3,256,161	8,351,313	355,439
Gross Operating Margin	\$2,199,934	\$7,107,769	(\$385,449)	\$1,230,936	\$7,242,796	\$4,196,591	\$4,478,780	\$9,528,318	\$40,545,742	\$1,735,030
Interest on Long-term Debt	1,217,653	2,827,102	253,078	1,347,642	3,951,256	1,106,754	1,601,131	5,241,838	10,349,046	867,422
Other Deductions	199,101	109,255	17,781	139,071	52,763	1,275	12,237	313,716	3,488	766,467
Net Margins	<u>\$783,180</u>	<u>\$4,171,412</u>	<u>(\$656,308)</u>	<u>(\$255,777)</u>	<u>\$3,238,777</u>	<u>\$3,088,562</u>	<u>\$2,865,412</u>	<u>\$3,972,764</u>	<u>\$30,193,208</u>	<u>\$101,141</u>
2021										
Operating Revenue & Patronage Capital	\$19,778,218	\$61,047,295	\$23,432,378	\$29,832,077	\$73,582,674	\$36,854,842	\$35,788,871	\$120,276,917	\$399,589,618	\$22,063,730
Depreciation and Amortization	1,981,542	4,610,725	1,694,580	2,393,510	5,993,376	2,703,177	2,987,839	7,943,365	22,186,511	1,263,554
Other Operating Expenses	16,409,661	51,740,825	20,382,093	25,145,169	62,751,579	29,972,252	29,544,524	104,305,004	343,161,555	17,871,152
Electric Operating Margin	\$1,387,015	\$4,695,745	\$1,355,705	\$2,293,398	\$4,837,719	\$4,179,413	\$3,256,508	\$8,028,548	\$34,241,552	\$2,929,024

Table 5 (Continued)

Other Income	396,674	1,420,160	181,261	762,113	3,362,998	255,892	950,836	1,914,045	4,639,601	511,447
Gross Operating Margin	\$1,783,689	\$6,115,905	\$1,536,966	\$3,055,511	\$8,200,717	\$4,435,305	\$4,207,344	\$9,942,593	\$38,881,153	\$3,440,471
Interest on Long-term Debt	974,539	2,576,283	217,650	1,454,874	3,267,113	1,064,662	1,468,661	3,748,871	9,650,691	808,040
Other Deductions	60,262	133,152	2,171	4,220	201,671	3,658	28,989	221,212	10,167	754,717
Net Margins	\$748,888	\$3,406,470	\$1,317,145	\$1,596,417	\$4,731,933	\$3,366,985	\$2,709,694	\$5,972,510	\$29,220,295	\$1,877,714

	Snapping Shoals	Southern Rivers	Sumter	Three Notch	Tri-County	Upson	Walton	Washington	MEMBER TOTAL
2023									
Operating Revenue & Patronage Capital	\$229,345,062	\$59,109,961	\$52,344,539	\$39,446,455	\$53,888,521	\$18,773,644	\$363,527,616	\$47,861,040	\$4,856,678,767
Depreciation and Amortization	12,454,916	5,554,183	4,584,911	2,891,117	5,361,774	1,040,948	17,325,291	3,252,776	350,632,032
Other Operating Expenses	209,351,331	46,367,654	43,042,232	28,783,533	40,998,773	14,698,173	327,798,062	40,972,291	4,120,840,789
Electric Operating Margin	\$7,538,815	\$7,188,124	\$4,717,396	\$7,771,805	\$7,527,974	3,034,523	\$18,404,263	\$3,635,973	\$385,205,946
Other Income	2,996,084	2,842,775	1,825,310	3,167,496	(339,449)	853,774	15,577,925	2,351,889	267,910,133
Gross Operating Margin	\$10,534,899	\$10,030,899	\$6,542,706	\$10,939,301	\$7,188,525	\$3,888,297	\$33,982,188	\$5,987,862	\$653,116,079
Interest on Long-term Debt	4,672,684	2,943,106	2,069,740	1,953,356	4,172,999	216,313	7,050,219	3,161,256	172,332,333
Other Deductions	142,039	-	406,304	88,921	592,063	17,876	422,588	-	17,064,596
Net Margins	\$5,720,176	\$7,087,793	\$4,066,662	\$8,897,024	\$2,423,463	\$3,654,108	\$26,509,381	\$2,826,606	\$463,719,150

2022									
Operating Revenue & Patronage Capital	\$261,499,170	\$53,748,494	\$53,016,834	\$35,705,405	\$56,266,746	\$17,963,752	\$376,778,069	\$47,019,852	\$5,042,843,838
Depreciation and Amortization	12,058,802	3,735,601	4,306,282	2,758,576	4,476,631	1,001,687	16,611,632	3,024,595	325,319,753
Other Operating Expenses	244,398,779	48,021,609	44,611,163	32,016,025	45,479,975	17,019,068	354,043,262	42,007,891	4,468,744,445
Electric Operating Margin	\$5,041,589	\$1,991,284	\$4,099,389	\$930,804	\$6,310,140	(\$57,033)	\$6,123,175	\$1,987,366	\$248,779,640
Other Income	3,053,358	1,164,815	1,337,128	4,366,873	(1,179,390)	494,893	7,562,039	802,631	204,027,243

Table 5 (Continued)

Gross Operating Margin	\$8,094,947	\$3,156,099	\$5,436,517	\$5,297,677	\$5,130,750	\$437,890	\$13,685,214	\$2,789,997	\$452,806,883
Interest on Long-term Debt	4,114,436	1,963,478	1,934,407	1,707,284	3,308,605	280,326	5,403,917	1,728,508	146,357,607
Other Deductions	42,420	500	215,812	34,847	30,893	16,092	300,869	-	7,593,900
Net Margins	\$3,938,091	\$1,192,121	\$3,286,298	\$3,555,546	\$1,791,252	\$141,472	\$7,980,428	\$1,061,489	\$298,855,376
2021									
Operating Revenue & Patronage Capital	\$210,137,699	\$45,199,127	\$47,821,664	\$31,965,809	\$48,411,586	\$15,073,652	\$337,549,051	\$39,341,139	\$4,446,949,405
Depreciation and Amortization	11,485,998	3,416,694	4,096,515	2,574,808	4,227,537	973,761	16,038,068	2,890,972	308,987,082
Other Operating Expenses	192,550,408	39,254,335	40,080,734	27,049,533	36,765,257	13,199,446	314,341,252	34,925,135	3,858,392,471
Electric Operating Margin	\$6,101,293	\$2,528,098	\$3,644,415	\$2,341,468	\$7,418,792	\$900,445	\$7,169,731	\$1,525,032	\$279,569,852
Other Income	2,781,657	435,299	1,305,154	646,324	(1,327,995)	378,900	7,311,106	852,968	167,494,004
Gross Operating Margin	\$8,882,950	\$2,963,397	\$4,949,569	\$2,987,792	\$6,090,797	\$1,279,345	\$14,480,837	\$2,378,000	\$447,063,856
Interest on Long-term Debt	4,035,854	1,575,534	1,976,951	1,699,418	2,441,356	200,098	5,055,913	1,326,124	137,243,757
Other Deductions	55,164	-	72,330	22,402	19,097	25,101	167,237	-	4,623,827
Net Margins	\$4,791,932	\$1,387,863	\$2,900,288	\$1,265,972	\$3,630,344	\$1,054,146	\$9,257,687	\$1,051,876	\$305,196,272

**FINANCIAL AND STATISTICAL INFORMATION FOR THE
38 MEMBERS OF OGLETHORPE POWER CORPORATION**

**Table 6
CONDENSED BALANCE SHEET INFORMATION OF EACH MEMBER
(as of December 31)**

	<u>Altamaha</u>	<u>Amicalola</u>	<u>Canochee</u>	<u>Carroll</u>	<u>Central Georgia</u>	<u>Coastal</u>	<u>Cobb</u>	<u>Colquitt</u>	<u>Coweta- Fayette</u>	<u>Diverse</u>
2023										
ASSETS										
Total Utility Plant (1)	\$193,795,964	\$280,108,748	\$188,085,999	\$371,684,336	\$432,196,863	\$168,067,591	\$1,087,732,079	\$383,254,777	\$462,691,430	\$315,277,784
Depreciation	49,694,703	96,097,801	54,388,383	105,282,767	53,883,597	38,958,400	324,414,755	132,448,055	153,203,893	111,140,347
Net Plant	144,101,261	184,010,947	133,697,616	266,401,569	378,313,266	129,109,191	763,317,324	250,806,722	309,487,537	204,137,437
Other Assets	60,145,493	55,135,910	41,226,256	63,771,453	101,840,651	32,995,791	456,307,067	101,625,479	159,705,578	49,857,062
Total Assets	\$204,246,754	\$239,146,857	\$174,923,872	\$330,173,022	\$480,153,917	\$162,104,982	\$1,219,624,391	\$352,432,201	\$469,193,115	\$253,994,499
EQUITY & LIABILITIES										
Equity	\$100,491,457	\$81,255,658	\$71,195,125	\$151,254,239	\$108,168,075	\$63,318,815	\$754,717,123	\$150,326,069	\$208,809,358	\$85,524,865
Long-term Debt	75,819,508	93,844,157	72,860,015	150,926,482	250,082,109	72,380,246	326,758,765	139,057,482	208,371,698	135,963,771
Other Liabilities	27,935,789	64,047,042	30,868,732	27,992,301	121,903,733	26,405,921	138,148,503	63,048,650	52,012,059	32,505,863
Total Equity and Liabilities	\$204,246,754	\$239,146,857	\$174,923,872	\$330,173,022	\$480,153,917	\$162,104,982	\$1,219,624,391	\$352,432,201	\$469,193,115	\$253,994,499
2022										
ASSETS										
Total Utility Plant (1)	\$168,772,625	\$265,816,628	\$176,399,666	\$343,948,470	\$357,636,123	\$150,257,207	\$1,041,956,909	\$364,339,508	\$436,286,157	\$295,205,313
Depreciation	45,590,296	93,694,979	52,501,813	98,762,539	62,555,311	35,854,378	313,174,767	122,293,338	147,135,853	102,377,286
Net Plant	123,182,329	172,121,649	123,897,853	245,185,931	295,080,812	114,402,829	728,782,142	242,046,170	289,150,304	192,828,027
Other Assets	63,027,533	54,319,547	39,883,474	51,273,826	99,005,741	37,676,689	444,680,410	101,422,886	145,277,399	45,763,159
Total Assets	\$186,209,862	\$226,441,196	\$163,781,327	\$296,459,757	\$394,086,553	\$152,079,518	\$1,173,462,552	\$343,469,056	\$434,427,703	\$238,591,186
EQUITY & LIABILITIES										
Equity	\$89,677,082	\$79,540,486	\$69,468,144	\$129,450,710	\$101,002,281	\$56,906,155	\$672,469,164	\$158,564,105	\$189,909,719	\$78,954,344
Long-term Debt	72,129,136	92,615,584	63,152,367	134,344,474	188,701,235	76,300,457	372,804,266	136,302,038	183,043,939	132,506,991
Other Liabilities	24,403,644	54,285,126	31,160,816	32,664,573	104,383,037	18,872,906	128,189,122	48,602,913	61,474,045	27,129,851
Total Equity and Liabilities	\$186,209,862	\$226,441,196	\$163,781,327	\$296,459,757	\$394,086,553	\$152,079,518	\$1,173,462,552	\$343,469,056	\$434,427,703	\$238,591,186

2021**ASSETS**

Total Utility Plant (1)	\$148,212,395	\$248,279,704	\$167,770,781	\$323,477,065	\$299,153,030	\$139,598,636	\$986,191,276	\$348,252,644	\$412,001,682	\$277,454,236
Depreciation	41,492,247	91,580,020	51,011,068	92,656,196	63,970,166	33,038,615	289,295,844	113,503,594	139,128,837	97,051,275
Net Plant	106,720,148	156,699,684	116,759,713	230,820,869	235,182,864	106,560,021	696,895,432	234,749,050	272,872,845	180,402,961
Other Assets	54,374,114	45,149,102	36,765,842	51,121,057	80,874,821	34,173,642	400,931,599	78,975,883	144,042,838	35,837,680
Total Assets	\$161,094,262	\$201,848,786	\$153,525,555	\$281,941,926	\$316,057,685	\$140,733,663	\$1,097,827,031	\$313,724,933	\$416,915,683	\$216,240,641
EQUITY & LIABILITIES										
Equity	\$88,011,983	\$81,097,276	\$70,845,186	\$126,840,419	\$97,786,250	\$56,355,574	\$564,357,405	\$138,898,489	\$188,198,511	\$72,104,987
Long-term Debt	55,417,383	73,989,675	54,767,552	124,144,796	151,173,121	68,572,500	382,090,190	122,847,254	136,365,969	119,310,020
Other Liabilities	17,664,896	46,761,835	27,912,817	30,956,711	67,098,314	15,805,589	151,379,436	51,979,190	92,351,203	24,825,634
Total Equity and Liabilities	\$161,094,262	\$201,848,786	\$153,525,555	\$281,941,926	\$316,057,685	\$140,733,663	\$1,097,827,031	\$313,724,933	\$416,915,683	\$216,240,641

Footnotes:**(1) Including construction work in progress.**

	Excelsior	Flint	Grady	GreyStone	Habersham	Hart	Irwin	Jackson	Jefferson	Little Ocmulgee
2023										
ASSETS										
Total Utility Plant (1)	\$115,612,932	\$544,026,983	\$137,278,972	\$714,152,484	\$251,208,115	\$216,442,254	\$149,037,751	\$1,353,766,401	\$215,689,488	\$77,684,203
Depreciation	30,702,839	203,956,519	29,956,660	166,498,527	95,696,285	72,096,945	47,821,900	447,373,965	57,325,141	22,196,203
Net Plant	84,910,093	340,070,464	107,322,312	547,653,957	155,511,830	144,345,309	101,215,851	906,392,436	158,364,347	55,488,000
Other Assets	53,549,848	143,933,137	52,798,495	171,027,625	54,855,173	111,312,344	28,457,868	466,128,937	17,745,876	10,467,000
Total Assets	\$138,459,941	\$484,003,601	\$160,120,807	\$718,681,582	\$210,367,003	\$255,657,653	\$129,673,719	\$1,372,521,373	\$176,110,223	\$65,955,000
EQUITY & LIABILITIES										
Equity	\$68,071,455	\$161,335,957	\$82,156,880	\$305,179,762	\$67,319,070	\$130,185,132	\$32,751,361	\$620,682,630	\$63,245,609	\$27,321,483
Long-term Debt	42,116,410	\$240,443,797	59,409,618	329,387,088	101,202,852	71,699,003	78,133,651	541,140,533	83,854,345	27,280,661
Other Liabilities	28,272,076	82,223,847	18,554,309	84,114,732	41,845,081	53,773,518	18,788,707	210,698,210	29,010,269	11,352,856
Total Equity and Liabilities	\$138,459,941	\$484,003,601	\$160,120,807	\$718,681,582	\$210,367,003	\$255,657,653	\$129,673,719	\$1,372,521,373	\$176,110,223	\$65,955,000
2022										
ASSETS										
Total Utility Plant (1)	\$105,467,366	\$506,114,203	\$126,169,028	\$667,441,746	\$227,476,773	\$206,434,064	\$125,298,592	\$1,272,588,313	\$206,209,210	\$75,652,518
Depreciation	28,447,832	189,861,618	29,506,763	151,956,175	89,020,164	68,656,605	44,451,694	416,329,238	53,674,362	21,975,064
Net Plant	77,019,534	316,252,585	96,662,265	515,485,571	138,456,609	137,777,459	80,846,898	856,259,075	152,534,848	53,677,454
Other Assets	48,161,873	123,348,356	45,730,443	123,057,066	50,492,567	105,349,320	26,351,823	449,969,252	15,926,673	13,070,461
Total Assets	\$125,181,407	\$439,600,941	\$142,392,708	\$638,542,637	\$188,949,176	\$243,126,779	\$107,198,721	\$1,306,228,327	\$168,461,521	\$66,747,915
EQUITY & LIABILITIES										
Equity	\$65,065,115	\$155,629,924	\$73,054,253	\$299,843,080	\$57,638,000	\$127,774,024	\$30,583,820	\$585,850,613	\$56,309,533	\$26,471,860
Long-term Debt	34,423,410	\$208,516,979	44,385,723	241,889,470	88,370,944	66,127,089	66,770,116	525,480,781	79,513,478	28,643,606
Other Liabilities	25,692,882	75,454,038	24,952,732	96,810,087	42,940,232	49,225,666	9,844,785	194,896,933	32,638,510	11,632,449
Total Equity and Liabilities	\$125,181,407	\$439,600,941	\$142,392,708	\$638,542,637	\$188,949,176	\$243,126,779	\$107,198,721	\$1,306,228,327	\$168,461,521	\$66,747,915
2021										
ASSETS										
Total Utility Plant (1)	\$98,185,339	\$484,095,363	\$121,118,711	\$636,053,981	\$204,630,282	\$198,139,595	\$110,147,432	\$1,210,339,737	\$199,293,533	\$73,095,734
Depreciation	26,278,401	178,957,775	28,035,372	136,713,423	84,318,490	65,284,825	41,351,890	392,615,368	50,267,110	20,998,145

Net Plant	71,906,938	305,137,588	93,083,339	499,340,558	120,311,792	132,854,770	68,795,542	817,724,369	149,026,423	52,097,589
Other Assets	47,454,331	90,454,412	40,250,932	108,986,359	43,497,406	95,223,719	19,716,521	406,578,826	13,676,313	10,998,586
Total Assets	\$119,361,269	\$395,592,000	\$133,334,271	\$608,326,917	\$163,809,198	\$228,078,489	\$88,512,063	\$1,224,303,195	\$162,702,736	\$63,096,175
EQUITY & LIABILITIES										
Equity	\$63,065,805	\$151,710,954	\$63,584,914	\$295,596,622	\$58,905,871	\$113,647,701	\$32,828,981	\$562,158,310	\$56,012,112	\$25,706,482
Long-term Debt	31,698,488	\$177,017,584	46,536,649	244,360,499	69,470,232	61,552,043	48,592,967	494,774,274	75,161,178	28,615,765
Other Liabilities	24,596,976	66,863,462	23,212,708	68,369,796	35,433,095	52,878,745	7,090,115	167,370,611	31,529,446	8,773,928
Total Equity and Liabilities	\$119,361,269	\$395,592,000	\$133,334,271	\$608,326,917	\$163,809,198	\$228,078,489	\$88,512,063	\$1,224,303,195	\$162,702,736	\$63,096,175

Footnotes:

(1) Including construction work in progress.

	Middle Georgia	Mitchell	Ocmulgee	Oconee	Okefenoke	Planters	Rayle	Satilla	Sawnee	Slash Pine
2023										
ASSETS										
Total Utility Plant ⁽¹⁾	\$112,583,167	213,272,218	\$84,848,632	\$92,898,623	\$237,629,416	\$100,101,134	\$125,352,198	\$355,910,348	\$832,047,282	\$60,833,408
Depreciation	16,128,669	46,316,116	24,975,110	30,238,570	78,578,451	28,813,123	40,958,477	55,174,351	143,289,958	11,563,053
Net Plant	96,454,498	166,956,102	59,873,522	62,660,053	159,050,965	71,288,011	84,393,721	300,735,997	688,757,324	49,270,355
Other Assets	14,719,315	55,656,682	25,340,831	25,965,486	48,216,547	45,522,072	26,260,805	89,620,816	288,721,407	21,251,914
Total Assets	\$111,173,813	\$222,612,784	\$85,214,353	\$88,625,539	\$207,267,512	\$116,810,083	\$110,654,526	\$390,356,813	\$977,478,731	\$70,522,269
EQUITY & LIABILITIES										
Equity	\$29,826,427	\$100,154,206	\$46,160,899	\$38,569,972	\$72,178,346	\$54,784,570	\$45,297,722	\$135,247,212	\$336,420,734	\$31,475,279
Long-term Debt	70,326,736	84,719,597	27,565,723	32,440,481	110,393,429	43,005,353	46,980,399	191,656,796	392,399,569	29,235,690
Other Liabilities	11,020,650	37,738,981	11,487,731	17,615,086	24,695,737	19,020,160	18,376,405	63,452,805	248,658,428	9,811,300
Total Equity and Liabilities	\$111,173,813	\$222,612,784	\$85,214,353	\$88,625,539	\$207,267,512	\$116,810,083	\$110,654,526	\$390,356,813	\$977,478,731	\$70,522,269
2022										
ASSETS										
Total Utility Plant ⁽¹⁾	\$81,350,448	193,375,419	\$71,746,494	\$89,026,945	\$224,650,439	\$93,726,622	\$118,907,708	\$295,606,356	\$784,334,597	\$53,733,210
Depreciation	15,930,213	42,446,838	24,998,650	28,374,036	74,860,769	26,891,011	38,816,722	55,681,743	136,296,312	11,258,332
Net Plant	65,420,235	150,928,581	46,747,844	60,652,909	149,789,670	66,835,611	80,090,986	239,924,613	648,038,285	42,474,878
Other Assets	19,680,875	46,770,846	17,910,618	24,759,254	45,178,468	44,625,955	25,864,529	109,829,025	291,893,284	19,798,013
Total Assets	\$85,101,110	\$197,699,427	\$64,658,462	\$85,412,163	\$194,968,138	\$111,461,566	\$105,955,515	\$349,753,638	\$939,931,569	\$62,272,891
EQUITY & LIABILITIES										
Equity	\$26,301,713	\$93,797,835	\$42,721,165	\$34,623,486	\$68,410,112	\$51,826,641	\$43,360,201	\$135,789,886	\$312,328,666	\$26,092,195
Long-term Debt	39,015,553	69,090,794	13,189,535	29,107,488	103,720,395	41,129,527	50,212,262	159,084,180	372,445,557	26,296,296
Other Liabilities	19,783,844	34,810,798	8,747,762	21,681,189	22,837,631	18,505,398	12,383,052	54,879,572	255,157,346	9,884,400
Total Equity and Liabilities	\$85,101,110	\$197,699,427	\$64,658,462	\$85,412,163	\$194,968,138	\$111,461,566	\$105,955,515	\$349,753,638	\$939,931,569	\$62,272,891
2021										
ASSETS										
Total Utility Plant ⁽¹⁾	\$63,783,298	185,640,808	\$66,367,916	\$85,800,828	\$212,313,316	\$89,236,765	\$113,606,593	\$252,484,233	\$729,046,717	\$50,298,782
Depreciation	16,217,688	39,584,048	24,304,725	26,710,055	73,021,959	25,343,124	37,260,688	55,770,533	133,207,655	10,848,915
Net Plant	47,565,610	146,056,760	42,063,191	59,090,773	139,291,357	63,893,641	76,345,905	196,713,700	595,839,062	39,449,867
Other Assets	13,128,225	41,893,075	16,688,950	23,284,212	39,950,610	42,064,042	21,736,146	72,002,922	285,933,651	19,899,391
Total Assets	\$60,693,835	\$187,949,835	\$58,752,141	\$82,374,985	\$179,241,967	\$105,957,683	\$98,082,051	\$268,716,622	\$881,772,713	\$59,349,258

EQUITY & LIABILITIES										
Equity	\$25,681,857	\$90,406,827	\$42,168,013	\$35,228,785	\$66,847,802	\$50,452,156	\$39,890,214	\$120,365,729	\$290,418,850	\$26,293,796
Long-term Debt	29,403,489	63,300,052	8,660,317	31,075,142	92,916,236	36,040,267	46,138,121	99,484,591	332,440,853	24,574,337
Other Liabilities	5,608,489	34,242,956	7,923,811	16,071,058	19,477,929	19,465,260	12,053,716	48,866,302	258,913,010	8,481,125
Total Equity and Liabilities	\$60,693,835	\$187,949,835	\$58,752,141	\$82,374,985	\$179,241,967	\$105,957,683	\$98,082,051	\$268,716,622	\$881,772,713	\$59,349,258

Footnotes:

(1) Including construction work in progress.

	Snapping Shoals	Southern Rivers	Sumter	Three Notch	Tri-County	Upson	Walton	Washington	MEMBER TOTAL
2023									
ASSETS									
Total Utility Plant ⁽¹⁾	\$371,935,599	\$170,572,649	\$161,429,604	\$102,199,270	\$197,057,855	\$35,274,651	\$561,654,955	\$134,624,497	\$11,608,020,660
Depreciation	161,313,239	36,211,208	39,810,755	35,133,166	37,909,068	14,646,231	223,372,946	37,948,328	3,355,518,504
Net Plant	210,622,360	134,361,441	121,618,849	67,066,104	159,148,787	20,628,420	338,282,009	96,676,169	8,252,502,156
Other Assets	106,107,464	40,829,658	38,377,755	43,322,978	20,973,102	20,328,104	300,855,527	46,851,953	3,491,809,459
Total Assets	\$316,729,824	\$175,191,099	\$159,996,604	\$110,389,082	\$180,121,889	\$40,956,524	\$639,137,536	\$143,528,122	\$11,744,311,615
EQUITY & LIABILITIES									
Equity	\$102,640,543	\$57,507,080	\$76,994,421	\$59,095,243	\$48,234,891	\$28,142,400	\$263,454,200	\$49,441,701	\$4,908,935,969
Long-term Debt	106,898,204	99,546,414	67,019,799	43,553,387	104,224,367	8,593,404	166,045,163	82,700,718	4,808,037,420
Other Liabilities	107,191,077	18,137,605	15,982,384	7,740,452	27,662,631	4,220,720	209,638,173	11,385,703	2,027,338,226
Total Equity and Liabilities	\$316,729,824	\$175,191,099	\$159,996,604	\$110,389,082	\$180,121,889	\$40,956,524	\$639,137,536	\$143,528,122	\$11,744,311,615
2022									
ASSETS									
Total Utility Plant ⁽¹⁾	\$349,192,776	\$145,748,290	\$150,290,327	\$99,116,524	\$175,645,900	\$33,468,079	\$531,241,510	\$120,005,874	\$10,730,637,937
Depreciation	152,112,096	32,962,735	37,622,838	32,975,555	34,735,450	14,171,795	212,521,461	37,837,019	3,178,313,650
Net Plant	197,080,680	112,785,555	112,667,489	66,140,969	140,910,450	19,296,284	318,720,049	82,168,855	7,552,324,287
Other Assets	110,425,816	33,000,188	39,657,862	37,442,287	21,967,870	19,481,723	258,126,580	37,055,119	3,287,256,810
Total Assets	\$307,506,496	\$145,785,743	\$152,325,351	\$103,583,256	\$162,878,320	\$38,778,007	\$576,846,629	\$119,223,974	\$10,839,581,097
EQUITY & LIABILITIES									
Equity	\$101,571,758	\$47,608,781	\$73,594,774	\$50,594,632	\$46,339,256	\$25,494,587	\$234,920,020	\$47,562,926	\$4,567,101,046
Long-term Debt	95,873,587	75,519,784	57,865,582	45,797,023	97,072,357	8,583,665	149,405,562	60,844,094	4,330,275,324
Other Liabilities	110,061,151	22,657,178	20,864,995	7,191,601	19,466,707	4,699,755	192,521,047	10,816,954	1,942,204,727
Total Equity and Liabilities	\$307,506,496	\$145,785,743	\$152,325,351	\$103,583,256	\$162,878,320	\$38,778,007	\$576,846,629	\$119,223,974	\$10,839,581,097
2021									
ASSETS									
Total Utility Plant ⁽¹⁾	\$331,579,681	\$114,541,647	\$142,001,583	\$95,284,016	\$148,577,527	\$32,536,138	\$506,594,363	\$100,680,327	\$10,005,865,694
Depreciation	142,435,632	31,316,095	35,812,629	30,571,811	32,063,729	13,306,492	201,135,009	36,823,381	3,003,282,829
Net Plant	189,144,049	83,225,552	106,188,954	64,712,205	116,513,798	19,229,646	305,459,354	63,856,946	7,002,582,865
Other Assets	108,794,642	46,625,749	40,533,418	29,144,645	18,102,018	18,915,651	221,942,978	33,894,396	2,933,618,704
Total Assets	\$297,938,691	\$129,851,301	\$146,722,372	\$93,856,850	\$134,615,816	\$38,145,297	\$527,402,332	\$97,751,342	\$9,936,201,569

EQUITY & LIABILITIES									
Equity	\$97,164,114	\$46,499,532	\$70,982,902	\$47,124,930	\$44,658,405	\$26,009,349	\$221,387,486	\$47,544,977	\$4,296,839,556
Long-term Debt	91,663,182	64,732,812	59,839,283	40,320,152	77,445,465	8,657,065	132,318,295	41,475,552	3,846,943,350
Other Liabilities	109,111,395	18,618,957	15,900,187	6,411,768	12,511,946	3,478,883	173,696,551	8,730,813	1,792,418,663
Total Equity and Liabilities	\$297,938,691	\$129,851,301	\$146,722,372	\$93,856,850	\$134,615,816	\$38,145,297	\$527,402,332	\$97,751,342	\$9,936,201,569

Footnotes:

(1) Including construction work in progress.



Offers to Exchange

\$350,000,000

**Registered
5.800% Green First Mortgage Bonds
Series 2024A due 2054**

for any and all

**Unregistered
5.800% Green First Mortgage Bonds,
Series 2024A due 2054**

and

\$350,000,000

**Registered
5.900% Green First Mortgage Bonds
Series 2025A due 2055**

for any and all

**Unregistered
5.900% Green First Mortgage Bonds,
Series 2025A due 2055**

**PROSPECTUS
, 2025**

No dealer, salesperson or other person is authorized to give any information or to represent anything not contained in this prospectus. You must not rely on any unauthorized information or representations. This prospectus is an offer to exchange only the Exchange Bonds offered hereby, but only under circumstances and in jurisdictions where it is lawful to do so. The information contained in this prospectus is current only as of its date.

PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 20. Indemnification of Directors and Officers

Georgia Statute

Section 46-3-306 of the Official Code of Georgia Annotated which governs indemnification of our officers and directors provides as follows:

46-3-306. Indemnification of officers, directors, employees, and agents; insurance.

- (a) As used in this Code section, the term “the electric membership corporation” shall include, in addition to the surviving or new electric membership corporation, any merging or consolidating electric membership corporation, including any merging or consolidating electric membership corporation of a merging or consolidating electric membership corporation, absorbed in a merger or consolidation so that any person who is or was a director, officer, employee, or agent of such merging or consolidating electric membership corporation, or is or was serving at the request of such merging or consolidating electric membership corporation as a director, officer, employee, or agent of another corporation, partnership, joint venture, trust, or other enterprise, shall stand in the same position under this Code section with respect to the resulting or surviving electric membership corporation as he would if he had served the resulting or surviving electric membership corporation in the same capacity, provided that no indemnification under subsections (b) and (c) of this Code section which are permitted by this subsection shall be mandatory under this subsection or any bylaw of the surviving or new electric membership corporation without the approval of such indemnification by the board of directors or members of the surviving or new electric membership corporation, in the manner provided in paragraphs (1) and (3) of subsection (e) of this Code section.
- (b) An electric membership corporation shall have power to indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending, or completed action or proceeding, whether civil, criminal, administrative, or investigative (other than an action by or in the right of the electric membership corporation), by reason of the fact that he is or was a director, officer, employee, or agent of the electric membership corporation, or is or was serving at the request of the electric membership corporation as a director, officer, employee, or agent of another corporation, partnership, joint venture, trust, or other enterprise, against expenses, including attorney’s fees, judgments, fines, and amounts paid in settlement actually and reasonably incurred by him in connection with such action or proceeding if he acted in a manner he reasonably believed to be in or not opposed to the best interests of the electric membership corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. The termination of any action or proceeding by judgment, order, settlement, or conviction, or upon a plea of nolo contendere or its equivalent, shall not of itself create a presumption that the person did not act in a manner which he reasonably believed to be in or not opposed to the best interests of the electric membership corporation and, with respect to any criminal action or proceeding, had reasonable cause to believe that his conduct was unlawful.
- (c) An electric membership corporation shall have the power to indemnify any person who was or is a party or who is threatened to be made a party to any threatened, pending, or completed action or suit by, or in the right of, the electric membership corporation to procure a judgment in its favor, by reason of the fact he is or was a director, officer, employee, or agent of the electric membership corporation or is or was serving at the request of the electric membership corporation as a director, employee, or agent of another corporation, partnership, joint venture, trust, or other enterprise, against expenses, including attorney’s fees, actually and reasonably incurred by him in connection with the defense or settlement of such action or suit, if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the electric membership corporation; except that no indemnification shall be made in respect to any claim, issue, or matter as to which such person shall have been adjudged to be liable to the electric membership corporation, unless and only to the extent that the court in which such action or suit was brought shall

determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses which the court shall deem proper.

- (d) To the extent that a director, officer, employee, or agent of an electric membership corporation has been successful, on the merits or otherwise, in defense of any action, suit, or proceeding referred to in subsections (b) and (c) of this Code section or in defense of any claim, issue, or matter therein, he shall be indemnified against expenses, including attorney's fees, actually and reasonably incurred by him in connection therewith.
- (e) Any indemnification under subsections (b) and (c) of this Code section, unless ordered by a court, shall be made by the electric membership corporation only as authorized in the specific case, upon a determination that indemnification of the director, officer, employee, or agent is proper in the circumstances because he has met the applicable standard of conduct set forth in subsections (b) and (c) of this Code section. Such determination shall be made:
 - (1) By the board of directors by a majority vote of a quorum consisting of directors who were not parties to such action, suit, or proceeding;
 - (2) If such a quorum is not obtainable or, even if obtainable, if a quorum of disinterested directors so directs, by independent legal counsel in a written opinion; or
 - (3) By the affirmative vote of the members present and voting at the meeting at which such determination is made.
- (f) Expenses incurred in defending a civil or criminal action, suit, or proceeding may be paid by the electric membership corporation in advance of the final disposition of such action, suit, or proceeding upon receipt of an undertaking by or on behalf of the director, officer, employee, or agent to repay such amount if it shall ultimately be determined that he is not entitled to be indemnified by the electric membership corporation as authorized in this Code section.
- (g) The indemnification and advancement of expenses provided by or granted pursuant to this Code section shall not be deemed exclusive of any other rights, in respect to indemnification or otherwise, to which those seeking indemnification or advancement of expenses may be entitled under any bylaw, resolution, or agreement, either specifically or in general terms approved by the affirmative vote of a majority of the members entitled to vote thereon, taken at a meeting, the notice of which specified that such bylaw, resolution, or agreement would be placed before the members, both as to action by a director, officer, employee, or agent in his official capacity and as to action in another capacity while holding such office or position, except that no such other rights, in respect to indemnification or otherwise, may be provided or granted to a director, officer, employee, or agent pursuant to this subsection by an electric membership corporation with respect to the liabilities described in divisions (b)(3)(A)(i) through (b)(3)(A)(iii) of Code Section 46-3-321.
- (h) An electric membership corporation shall have the power to purchase and maintain insurance on behalf of any person who is or was a director, officer, employee, or agent of the electric membership corporation or who is or was serving at the request of the electric membership corporation as a director, officer, employee, or agent of another corporation, partnership, joint venture, trust, or other enterprise, against any liability asserted against him and incurred by him in any such capacity, or arising out of his status as such, whether or not the electric membership corporation would have the power to indemnify him against such liability under this Code section.
- (i) If any expenses or other amounts are paid by way of indemnification, otherwise than by court order or action by the members or by an insurance carrier pursuant to insurance maintained by the electric membership corporation, the electric membership corporation, not later than the next annual meeting of members, unless such meeting is held within three months from the date of such payment, and in any event, within 15 months from the date of such payment, shall send to its members who are entitled to vote for the

election of directors a statement specifying the persons paid, the amounts paid, and the nature and status at the time of such payment of the litigation or threatened litigation. Such statement shall be provided to the members in the manner provided in subsection (a) of Code Section 46-3-263 for giving notice of members' meetings.

- (j) The indemnification and advancement of expenses provided by or granted pursuant to this Code section shall, unless otherwise provided when authorized or ratified, continue as to a person who has ceased to be a director, officer, employee, or agent and shall inure to the benefit of the heirs, executors, and administrators of such a person. (Code 1933, § 34C-617, enacted by Ga. L. 1981, p. 1587, § 1; Ga. L. 1988, p. 1451, § 2; Ga. L. 1989, p. 14, § 46.)

Articles of Incorporation

Our Restated Articles of Incorporation contain the following provision:

“Article VII. A director of the Corporation shall not be personally liable to the Corporation or its members for monetary damages for breach of duty of care or other duty as a director, except for liability:

- (i) For any appropriation, in violation of his duties, of any business opportunity of the Corporation;
- (ii) For acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law; or
- (iii) For any transaction from which the director derives an improper personal benefit.

The liability of directors shall be deemed further limited or eliminated to the fullest extent permitted by changes in the law governing the Corporation. Any repeal or modification of the provisions of this Article VII shall not adversely affect the duty, liability, rights or protection of a director existing at the time of such repeal or modification.”

Bylaws

Our bylaws contain the following provisions relating to indemnification and insurance:

Article IX Indemnification and Insurance

Section 1. Indemnification.

The Corporation shall indemnify each person who is or was a Director, officer, employee or agent of the Corporation (including the heirs, executors, administrators or estate of such person) or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise to the full extent permitted under Sections 46-3-306(b), (c) and (d) of the Georgia Electric Membership Corporation Act or any successor provisions of the laws of the State of Georgia. If any such indemnification is requested pursuant to Sections 46-3-306(b) or (c) of said Act or laws, the Board of Directors shall cause a determination to be made (unless a court has ordered the indemnification) in one of the manners prescribed in Section 46- 3-306(e) of said Act or laws as to whether indemnification of the party requesting indemnification is proper in the circumstances because he has met the applicable standard of conduct set forth in Sections 46-3-306(b) or (c) of said Act or laws. Upon any such determination that such indemnification is proper, the Corporation shall make indemnification payments of liability, cost, payment or expense asserted against, or paid or incurred by, him in his capacity as such a director, officer, employee or agent to the maximum extent permitted by said Sections of said Act or laws. The indemnification obligation of the Corporation set forth herein shall not be deemed exclusive of any other rights, in respect of indemnification or otherwise, to which any party may be entitled under any other bylaw provision or resolution approved by the members pursuant to Section 46-3- 306(g) of said Act or laws.

Section 2. Insurance.

The Corporation may purchase and maintain insurance at its expense, to protect itself and any Director, officer, employee or agent of the Corporation (including the heirs, executors, administrators or estate of any such person) against any liability, cost, payment or expense described in Section 1 of this Article IX, whether or not the Corporation would have the power to indemnify such person against such liability.”

Insurance

We maintain director and officer insurance policies which insure our present and former directors and officers against certain claims and liabilities asserted against them in their capacities or arising out of their status as our directors and officers.

Item 21. Exhibits and Financial Statement Schedules

(a) **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 March 25, 2024. (Filed as Exhibit 3.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2024. File No. 333-192954.)
*4.1	— Thirteenth Amended and Restated Loan Contract, dated as of May 30, 2024, between Oglethorpe and the United States of America. (Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2024, File No. 333-192954.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)
*4.2.1(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.)

- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)

- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)

- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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 4.7.1\(qq\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2007, File No. 33-7591.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2009, File No. 333-159338.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarter ended September 30, 2009, File No. 333-159338.\)](#)
- *4.2.1(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.\)](#)

- *4.2.1 (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.\)](#)
- *4.2.1 (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.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010, File No. 000-53908.\)](#)
- *4.2.1 (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 \(relating to the Hawk Road and Hartwell Energy Facilities\). \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2010, File No. 000-53908.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2010, File No. 000-53908.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 8, 2010, File No. 000-53908.\)](#)
- *4.2.1 (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.\)](#)
- *4.2.1 (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.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2011, File No. 000-53908.\)](#)
- *4.2.1 (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. \(filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2011, File No. 000-53908.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2012, File No. 000-53908.\)](#)
- *4.2.1 (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. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 28, 2012, File No. 000-53908.\)](#)

- *4.2.1(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. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.4 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2013, File No. 000-53908.\)](#)
- *4.2.1(ppp) — [Sixty-Seventh Supplemental Indenture, dated as of February 1, 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. \(Filed as Exhibit 4.8 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on June 11, 2014, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2014, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2015, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2015, File No. 000-53908.\)](#)
- *4.2.1(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. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on April 19, 2016, File No. 000-53908.\)](#)
- *4.2.1(vvv) — [Seventy-Third Supplemental Indenture, dated as of July 26, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, confirming the lien of the Indenture with respect to certain agreements and licenses. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2017, File No. 333-192954.\)](#)
- *4.2.1(www) — [Seventy-Fourth Supplemental Indenture, dated as of October 1, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2017A \(Burke\) Note, the Series 2017B \(Burke\) Note, the Series 2017A \(Heard\) Note and the Series 2017A \(Monroe\) Note. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2017, File No. 333-192954.\)](#)
- *4.2.1(xxx) — [Seventy-Fifth Supplemental Indenture, dated as of October 18, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Amendment of the Original Indenture. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2017, File No. 333-192954.\)](#)
- *4.2.1(yyy) — [Seventy-Sixth Supplemental Indenture, dated as of December 1, 2017, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2017C \(Burke\) Note, the Series 2017D \(Burke\) Note, the Series 2017E \(Burke\) Note and the Series 2017F \(Burke\) Note. \(Filed as Exhibit 4.2.1\(yyy\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2017, File No. 333-192954.\)](#)

- *4.2.1(zzz) — [Seventy-Seventh Supplemental Indenture, dated as of January 30, 2018, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2018 \(FFB AC-8\) Note and Series 2018 \(RUS AC-8\) Reimbursement Note. \(Filed as Exhibit 4.2.1\(zzz\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2017, File No. 333-192954.\)](#)
- *4.2.1(aaaa) — [Seventy-Eighth Supplemental Indenture, dated as of October 1, 2018, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2018A. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on October 30, 2018, File No. 333-192954.\)](#)
- *4.2.1(bbbb) — [Seventy-Ninth Supplemental Indenture, dated as of March 1, 2019, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Future Advance Promissory Note and Reimbursement Note. \(Filed as Exhibit 4.6 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- *4.2.1(cccc) — [Eightieth Supplemental Indenture, dated as of August 1, 2020, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2020A. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 19, 2020, File No. 333-192954.\)](#)
- *4.2.1(dddd) — [Eighty-First Supplemental Indenture, dated as of December 3, 2020, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2020 \(FFB AD48\) Note and Series 2020 \(RUS AD48\) Reimbursement Note and Amendment of the Original Indenture. \(Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on December 9, 2020, File No. 333-192954.\)](#)
- *4.2.1(eeee) — [Eighty-Second Supplemental Indenture, dated as of October 6, 2021, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Recording the Indenture in Effingham County, GA. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2021, File No. 333-192954.\)](#)
- *4.2.1(ffff) — [Eighty-Third Supplemental Indenture, dated as of April 1, 2022, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2022A. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on April 7, 2022, File No. 333-192954.\)](#)
- *4.2.1(gggg) — [Eighty-Fourth Supplemental Indenture, dated as of October 18, 2022, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to the Series 2022 \(FFB AE48\) Note, Series 2022 \(RUS AE48\) Reimbursement Note. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2022, File No. 333-192954.\)](#)
- *4.2.1(hhhh) — [Eighty-Fifth Supplemental Indenture, dated as of February 6, 2023, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to conforming the lien of the indenture with respect to certain after-acquired property. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2023, File No. 333-192954.\)](#)
- *4.2.1(iiii) — [Eighty-Sixth Supplemental Indenture, dated as of May 25, 2023, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to recording the indenture in Mitchell County, Georgia. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2023, File No. 333-192954.\)](#)
- *4.2.1(jjjj) — [Eighty-Seventh Supplemental Indenture, dated as of December 1, 2023, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to Oglethorpe Power Corporation First Mortgage Bonds, Series 2023A. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on December 1, 2023, File No. 333-192954.\)](#)
- *4.2.1(kkkk) — [Eighty-Eighth Supplemental Indenture, dated as of May 30, 2024, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2024 \(FFB AF48\) Note, Series 2024 \(RUS AF48\) Reimbursement Note, Series 2024 \(FFB AG48\) Note, Series 2024 \(RUS AG48\) Reimbursement Note, Series 2024 \(FFB AH48\) Note and Series 2024 \(RUS AH48\) Reimbursement Note. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2024, File No. 333-192954.\)](#)
- *4.2.1(llll) — [Eighty-Ninth Supplemental Indenture, dated as of June 1, 2024, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Oglethorpe Power Corporation Green First Mortgage Bonds, Series 2024A. \(Filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2024, File No. 333-192954.\)](#)

- *4.2.1(mmmm) — [Ninetieth Supplemental Indenture, dated as of January 1, 2025, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to Oglethorpe Power Corporation Green First Mortgage Bonds, Series 2025A, \(Filed as Exhibit 4.2.1\(mmmm\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.\)](#)
- *4.2.2 — [Security Agreement, dated as of March 1, 1997, made by Oglethorpe to SunTrust Bank, Atlanta, as trustee. \(Filed as Exhibit 4.8.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.\)](#)
- *4.3 — [Unsecured Indenture, dated as of December 22, 2010, by and between Oglethorpe and U.S. Bank National Association, as trustee. \(Filed as Exhibit 4.1 to the Registrant's Form S-3 Registration Statement, File No. 333-171342.\)](#)
- 4.4.1⁽¹⁾ — Loan Agreement, dated as of April 1, 2013, between the Development Authority of Appling County and Oglethorpe relating to the Development Authority of Appling County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Hatch Project), Series 2013A, and two other substantially identical (Term Rate and Weekly Rate Bonds) loan agreements.
- 4.4.2⁽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 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.
- 4.4.3⁽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.
- 4.5.1⁽¹⁾ — Loan Agreement, dated as of October 1, 2017, between the Development Authority of Burke County and Oglethorpe relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical (Indexed Put Rate Bonds) loan agreements.
- 4.5.2⁽¹⁾ — Note, dated October 12, 2017, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of October 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical notes.
- 4.5.3⁽¹⁾ — Trust Indenture, dated as of October 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association, as trustee, relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical indentures.
- 4.5.4⁽¹⁾ — Bondholder's Agreement, dated as of October 1, 2017, by and between Oglethorpe and RBC Municipal Products, LLC, relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017A, and two other substantially identical bondholder's agreements.
- 4.6.1⁽¹⁾ — Loan Agreement, dated as of December 1, 2017, between the Development Authority of Burke County and Oglethorpe relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017C, and two other substantially identical (Fixed Rate and Term Rate Bonds) loan agreements.
- 4.6.2⁽¹⁾ — Note, dated December 28, 2017, from Oglethorpe to U.S. Bank National Association, as trustee, acting pursuant to a Trust Indenture, dated as of December 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017C, and two other substantially identical notes.
- 4.6.3⁽¹⁾ — Trust Indenture, dated as of December 1, 2017, between the Development Authority of Burke County and U.S. Bank National Association, as trustee, relating to the Development Authority of Burke County Pollution Control Revenue Bonds (Oglethorpe Power Corporation Vogtle Project), Series 2017C, and two other substantially identical indentures.

- *4.7.1 — [Note Purchase Agreement, dated February 20, 2014, between Oglethorpe, Federal Financing Bank and United States Department of Energy. \(Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.7.2 — [Future Advance Promissory Note No. 1, dated February 20, 2014, from Oglethorpe to Federal Financing Bank. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.7.3 — [Future Advance Promissory Note No. 2, dated February 20, 2014, from Oglethorpe to Federal Financing Bank. \(Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.7.4 — [Note Purchase Agreement, dated as of March 22, 2019, between Oglethorpe, Federal Financing Bank and the United States Department of Energy. \(Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- *4.7.5 — [Future Advance Promissory Note, dated March 22, 2019, from Oglethorpe to Federal Financing Bank. \(Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- *4.7.6 — [Loan Guarantee Agreement, dated February 20, 2014, between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.4 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.7.6(a) — [Amendment No. 1, dated as of June 4, 2015, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2017, File No. 333-192954.\)](#)
- *4.7.6(b) — [Amendment No. 2, dated as of March 9, 2016, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.3 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2017, File No. 333-192954.\)](#)
- *4.7.6(c) — [Amendment No. 3, dated as of July 27, 2017, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on July 28, 2017, File No. 333-192954.\)](#)
- *4.7.6(d) — [Amendment No. 4, dated as of December 8, 2017, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on December 11, 2017, File No. 333-192954.\)](#)
- *4.7.6(e) — [Amendment No. 5 and Waiver, dated as of March 7, 2019, to the Loan Guarantee Agreement between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on March 13, 2019, File No. 333-192954.\)](#)
- *4.7.6(f) — [Amended and Restated Loan Guarantee Agreement, dated as of March 22, 2019, between Oglethorpe and the United States Department of Energy, acting by and through the Secretary of Energy. \(Filed as Exhibit 4.3 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- *4.7.6(g) — [Amendment No.1 to Amended and Restated Loan Guarantee Agreement, dated December 3, 2020, between Oglethorpe and the Department of Energy. \(Filed as Exhibit 4.9.6\(g\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2020, File No. 333-192954.\)](#)
- *4.7.7 — [Reimbursement Note No. 1, dated February 20, 2014, issued by Oglethorpe to the Department of Energy. \(Filed as Exhibit 4.5 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.7.8 — [Reimbursement Note No. 2, dated February 20, 2014, issued by Oglethorpe to the Department of Energy. \(Filed as Exhibit 4.6 to the Registrant's Form 8-K filed on February 20, 2014, File No. 000-53908.\)](#)
- *4.7.9 — [Reimbursement Note, dated March 22, 2019, issued by Oglethorpe to the Department of Energy. \(Filed as Exhibit 4.4 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- 4.8 — [Exchange and Registration Rights Agreement, dated June 21, 2024, by and between RBC Capital Markets, LLC, on behalf of itself and the other purchasers identified therein.](#)
- 4.9 — [Exchange and Registration Rights Agreement, dated January 27, 2025, by and between J.P. Morgan Securities LLC, on behalf of itself and the other purchasers identified therein.](#)
- 5.1 — [Opinion of Eversheds Sutherland \(US\) LLP](#)

- *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 Sun Trust 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 — [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. \(Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-42759.\)](#)
- *10.1.4(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.)
- *10.1.4(b) — First Supplement to Lease Agreement No. 2 (included as Exhibit B to the Supplemental Participation Agreement No. 2 listed as Exhibit 10.1.1(b)).
- *10.1.4(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.)
- *10.1.4(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.\)](#)

- *10.1.5(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.)
- *10.1.5(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.)
- *10.1.5(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.\)](#)
- *10.1.6(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.)
- *10.1.6(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.)
- *10.1.6(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.\)](#)
- *10.1.7(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.)
- *10.1.7(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.\)](#)
- *10.1.8 — 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.)
- *10.1.9(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.)

- *10.1.9(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.)
- *10.2.2(d) — [Third Amendment to Plant Robert W. Scherer Units One and Two Operating Agreement Among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia and City of Dalton, Georgia, dated as of February 22, 2022. \(Filed as Exhibit 10.2.2\(d\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2021, File No. 333-192954.\)](#)
- *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) — [Amendment regarding Additional Participating Party Rights and Amendment No. 3 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement and Amendment No. 4 to Plant Vogtle Owners Agreement Authorizing Development, Construction, Licensing, and Operation of Additional Generating Units, dated as of November 2, 2017, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia. \(Filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2017, File No. 333-192954.\)](#)
- *10.3.2(d) — [Global Amendments to Vogtle Additional Units Agreements, dated as of February 18, 2019, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia. \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on February 20, 2019, File No. 333-192954.\)](#)
- *10.3.2(e) — [Amended and Restated 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, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia, dated as of March 22, 2019. \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- *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. \(Filed as Exhibit 10.4.3 to the Registrant's Form 8-K filed on April 27, 2006, File No. 33-7591.\)](#)
- *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 — [Settlement Agreement dated as of June 9, 2017, by and among Georgia Power Company, Oglethorpe, Municipal Electric Authority of Georgia, The City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Toshiba Corporation. \(Incorporated by reference to Exhibit 10.1 of Georgia Power Company's Form 8-K dated June 16, 2017, filed with the SEC on June 16, 2017.\)](#)
- *10.3.4(a) — [Settlement Agreement Amendment No. 1 to Settlement Agreement, dated December 8, 2017, among Georgia Power, Oglethorpe, the Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities and the Toshiba Corporation. \(Incorporated by reference to Exhibit 10.1 of Georgia Power Company's Form 8-K dated December 8, 2017, filed with the SEC on December 11, 2017.\)](#)
- *10.3.5⁽²⁾ — [Amended and Restated Services Agreement, dated as of July 20, 2017, by and among Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Westinghouse Electric Company LLC and WECTEC Global Project Services Inc. \(Incorporated by reference to Exhibit 10.1 of Georgia Power Company's Form 8-K dated February 1, 2024, filed with the SEC on February 1, 2024.\)](#)
- *10.3.6(a)⁽²⁾ — [Construction Completion Agreement dated as of October 23, 2017, between Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, and Bechtel Power Corporation. \(Incorporated by reference to Exhibit 10\(c\)\(8\) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2017, filed with the SEC on February 21, 2018.\)](#)
- *10.3.6(b)⁽²⁾ — [Amendment No. 1 to Construction Completion Agreement dated as of October 12, 2018, between Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia and Bechtel Power Corporation. \(Incorporated by reference to Exhibit 10\(c\)\(10\) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2018, filed with the SEC on February 20, 2019.\)](#)
- *10.3.6(c) — [Amendment No. 2 to Construction Completion Agreement dated as of November 8, 2019, between Georgia Power Company, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and the City of Dalton, Georgia and Bechtel Power Corporation. \(Incorporated by reference to Exhibit 10\(c\)\(8\) of Georgia Power Company's Form 10-K for the fiscal year ended December 31, 2019, filed with the SEC on February 20, 2020.\)](#)
- *10.3.7 — [Settlement Agreement and Release, dated as of October 5, 2023 by and between Georgia Power Company and Oglethorpe Power Corporation \(An Electric Membership Corporation\). \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 6, 2023, File No. 333-192954.\)](#)
- *10.4.1 — 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.)
- *10.4.2 — 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.)
- *10.5.1 — 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.)
- *10.5.2 — 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.)

- *10.6.1(a) — [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. \(Filed as Exhibit 10.31.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003, File No. 33-7591.\)](#)
- *10.6.1(b) — [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. \(Filed as Exhibit 10.8.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2005, File No. 33-7591.\)](#)
- *10.6.1(c) — [Second Amendment to Amended and Restated Wholesale Power Contract, dated as of November 15, 2023 between Oglethorpe and Altamaha Electric Membership Corporation, together with a schedule identifying 37 other substantially identical Second Amendments\). \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 17, 2023, File No. 333-192954.\)](#)
- *10.6.2 — [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. \(Filed as Exhibit 10.31.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003, File No. 33-7591.\)](#)
- *10.6.3 — [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. \(Filed as Exhibit 10.8.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.\)](#)
- *10.6.4 — [Wholesale Power Contract, dated November 1, 2009, between Oglethorpe and Flint Electric Membership Corporation. \(Filed as Exhibit 10.8.8 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.\)](#)
- *10.6.5 — [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. \(Filed as Exhibit 10.8.9 to the Registrant's Form 10-K for the fiscal year ended December 31, 2009, File No. 000-53908.\)](#)
- *10.7 — [ITSA, Power Sale and Coordination Umbrella Agreement between Oglethorpe and Georgia Power Company, dated as of November 12, 1990. \(Filed as Exhibit 10.28 to the Registrant's Form 8-K, filed January 4, 1991, File No. 33-7591.\)](#)
- *10.8 — [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.\)](#)
- *10.8(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.\)](#)
- *10.8(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.\)](#)
- *10.9 — [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. \(Filed as Exhibit 10.30 to the Registrant's Form 8-K, filed January 4, 1991, File No. 33-7591.\)](#)
- *10.10.1(a) — [Member Transmission Service Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia Transmission Corporation \(An Electric Membership Corporation\). \(Filed as Exhibit 10.33.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.\)](#)

- *10.10.1(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 \(An Membership Corporation\). \(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.\)](#)
- *10.10.1(c) — [Agreement to Extend the Term of the Member Transmission Service Agreement, dated as of December 30, 2024, by and between Oglethorpe and Georgia Transmission Corporation \(An Electric Membership Corporation.\) \(Filed as Exhibit 10.10.1\(c\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.\)](#)
- *10.10.2 — [Generation Services Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia System Operations Corporation. \(Filed as Exhibit 10.33.2 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.\)](#)
- *10.10.3 — [Operation Services Agreement, dated as of March 1, 1997, by and between Oglethorpe and Georgia System Operations Corporation. \(Filed as Exhibit 10.33.3 to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.\)](#)
- *10.11 — [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. \(Filed as Exhibit 10.27 to the Registrant's Form 10-Q for the quarterly period ended March 31, 1999, File No. 33-7591.\)](#)
- *10.12(a) — [Amended and Restated Credit Agreement, dated as of December 11, 2019, among Oglethorpe, as borrower, and the lenders identified therein, including National Rural Utilities Cooperative Finance Corporation, as administrative agent. \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on December 11, 2019, File No. 333-192954.\)](#)
- *10.12(b) — [Amendment No. 1 to Amended and Restated Credit Agreement, dated as of May 31, 2023, between Oglethorpe, as borrower, and National Rural Utilities Cooperative Finance Corporation, as administrative agent. \(Filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2023, File No. 333-192954.\)](#)
- *10.12(c) — [Amendment No. 2 to Amended and Restated Credit Agreement, dated as of May 23, 2024, between Oglethorpe, as borrower, and National Rural Utilities Cooperative Finance Corporation, as administrative agent. \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on May 30, 2024, File No. 333-192954.\)](#)
- *10.13⁽³⁾ — [Amended and Restated Employment Agreement, dated as of November 5, 2024, between Oglethorpe and Annalisa M. Bloodworth. \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 12, 2024, File No. 333-192954.\)](#)
- *10.14(a)⁽³⁾ — [Amended and Restated Employment Agreement, dated as of January 1, 2025, between Oglethorpe and Elizabeth B. Higgins. \(Filed as Exhibit 10.14\(a\)\(3\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.\)](#)
- *10.14(b)⁽³⁾ — [Retention Incentive Agreement, dated as of December 9, 2024, between Oglethorpe and Elizabeth B. Higgins. \(Filed as Exhibit 10.14\(b\)\(3\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.\)](#)
- *10.15⁽³⁾ — [Amended and Restated Employment Agreement, dated as of January 1, 2025, between Oglethorpe and William F. Ussery. \(Filed as Exhibit 10.15\(3\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.\)](#)
- 14.1 — Code of Conduct, available on our website, www.opc.com.
- 23.1 — [Consent of Ernst & Young LLP](#)
- 23.2 — [Consent of Eversheds Sutherland \(US\) LLP \(included in Exhibit 5.1 hereof\)](#)
- 24.1 — [Power of Attorney \(included on signature page\)](#)
- 25.1 — [Form T-1 Statement of Eligibility of U.S. Bank Trust Company, National Association, as Trustee](#)
- 99.1 — [Form Letter of Transmittal](#)
- 99.2 — [Form Notice of Guaranteed Delivery](#)
- 99.3 — [Form of Letters to Brokers, Dealers, Commercial Banks, Trust Companies and Other Nominees](#)
- 99.4 — [Form of Letter to Clients](#)
- 101 — XBRL Interactive Data File.

- 104 — Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101).
107 — [Filing Fee Table](#)

- (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.

(b) Financial Statement Schedules:

None applicable.

Item 22. Undertakings

(a) the undersigned registrant hereby undertakes:

- (1) to file, during any period in which offers and sales are being made, a post-effective amendment to this registration statement:
 - (i) to include any prospectus required by Section 10(a)(3) of the Securities Act;
 - (ii) to reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement. Notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities offered would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Securities and Exchange Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represent no more than a 20 percent change in the maximum aggregate offering price set forth in the “Calculation of Registration Fee” table in the effective registration statement; and
 - (iii) to include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.
- (2) that, for the purpose of determining any liability under the Securities Act, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof;
- (3) to remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering;
- (4) that, for the purpose of determining liability under the Securities Act to any purchaser, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness; provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use; and

- (5) that, for the purpose of determining liability of the registrant under the Securities Act to any purchaser in the initial distribution of the securities, the undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:
- (i) any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;
 - (ii) any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;
 - (iii) the portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and
 - (iv) any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.
- (b) Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.
- (c) The undersigned registrant hereby undertakes to respond to requests for information that is incorporated by reference into the prospectus pursuant to Item 4, 10(b), 11 or 13 of Form S-4 within one business day of receipt of such request and to send the incorporated documents by first class mail or equally prompt means. This includes information contained in documents filed subsequent to the effective date of the registration statement through the date of responding to the request.
- (d) The undersigned registrant hereby undertakes to supply by means of a post-effective amendment all information concerning a transaction, and the company being acquired involved therein, that was not the subject of and included in the registration statement when it became effective.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
<u>/s/ ANNALISA M. BLOODWORTH</u> ANNALISA M. BLOODWORTH	President and Chief Executive Officer (Principal Executive Officer)	April 2, 2025
<u>/s/ ELIZABETH B. HIGGINS</u> ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	April 2, 2025
<u>/s/ KATHRYN N. CURTIS</u> KATHRYN N. CURTIS	Vice President, Controller (Principal Accounting Officer)	April 2, 2025
<u>/s/ JIMMY G. BAILEY</u> JIMMY G. BAILEY	Director	April 2, 2025
<u>/s/ KEVIN W. BUSH</u> KEVIN W. BUSH	Director	April 2, 2025
<u>/s/ RONNIE M. HENDRICKS</u> RONNIE M. HENDRICKS	Director	April 2, 2025
<u>/s/ ERNEST A. JAKINS, III</u> ERNEST A. JAKINS, III	Director	April 2, 2025
<u>/s/ FRED MCWHORTER</u> FRED MCWHORTER	Director	April 2, 2025
<u>/s/ MARSHALL S. MILLWOOD</u> MARSHALL S. MILLWOOD	Director	April 2, 2025
<u>/s/ JEFFREY W. MURPHY</u> JEFFREY W. MURPHY	Director	April 2, 2025
<u>/s/ DANNY L. NICHOLS</u> DANNY L. NICHOLS	Director	April 2, 2025
<u>/s/ SAMMY G. SIMONTON</u> SAMMY G. SIMONTON	Director	April 2, 2025
<u>/s/ CHRISTOPHER L. STEPHENS</u> CHRISTOPHER L. STEPHENS	Director	April 2, 2025
<u>/s/ HORACE H. WEATHERSBY, III</u> HORACE H. WEATHERSBY, III	Director	April 2, 2025
<u>/s/ GEORGE L. WEAVER</u> GEORGE L. WEAVER	Director	April 2, 2025
<u>/s/JAMES I. WHITE</u> JAMES I. WHITE	Director	April 2, 2025