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

FORM 10-K

(Mark One)

☒

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

For the fiscal year ended December 31, 2025

OR

☐

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

For the Transition Period From _____ to _____

Commission File No. 333-192954

OGLETHORPE POWER CORPORATION

(An Electric Membership Corporation)

(Exact name of registrant as specified in its charter)

Georgia

(State or other jurisdiction of
incorporation or organization)

58-1211925

(I.R.S. employer
identification no.)

**2100 East Exchange Place
Tucker, Georgia**

(Address of principal executive offices)

30084-5336

(Zip Code)

Registrant's telephone number, including area code:

(770) 270-7600

Securities registered pursuant to Section 12(b) of the Act:

None

Securities registered pursuant to Section 12(g) of the Act:

None

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

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

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

Indicate by check mark whether the registrant has submitted every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **Yes** ☒ **No** ☐

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

Large accelerated filer ☐ Accelerated filer ☐ Non-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 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

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

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

Documents Incorporated by Reference: **None**

OGLETHORPE POWER CORPORATION**2025 FORM 10-K ANNUAL REPORT****Table of Contents**

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K contains "forward-looking statements." All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as 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 annual report. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this annual report may not occur.

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

- cost increases and schedule delays with respect to our capital improvement and construction projects, such as our 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;
- 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;
- 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;
- 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 for 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, severe winter weather, explosions, pandemic health events, or similar occurrences;
- significant changes in critical accounting policies material to us; and
- other factors discussed elsewhere in this annual report and in other reports we file with the SEC.

ITEM 1. BUSINESS

OGLETHORPE POWER CORPORATION

General

We are a Georgia electric membership corporation (an EMC) incorporated in 1974 and headquartered in metropolitan Atlanta. We are owned by our 38 retail electric distribution cooperative members. Our principal business is providing wholesale electric power to our members. As with cooperatives generally, we operate on a not-for-profit basis. We are one of the largest electric cooperatives in the United States in terms of revenues, assets, kilowatt-hour sales to members and, through our members, consumers served. We are also the second largest power supplier in the state of Georgia. As of December 31, 2025, we had 401 employees.

Our members are local consumer-owned distribution cooperatives that provide retail electric service on a not-for-profit basis. In general, our members' customer base consists of residential, commercial and industrial consumers within specific geographic areas. Our members serve approximately 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 annual report on Form 10-K.

Cooperative Principles

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

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

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 2025, we supplied energy that accounted for approximately 72% 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, 2025, our fleet of generating units totaled 9,317 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, coal, natural gas, fuel 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 2025, 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 2025.

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, 2025, our equity ratio was 9.9%.

As of December 31, 2025, we had approximately \$12.6 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 and government shutdowns. The proposed budget for fiscal year 2026, which began October 2025, includes an aggregate loan program level of \$7.0 billion and recent annual appropriations bills have provided the Rural Utilities Service an administrative process through which it may increase available loan funding by up to 25%. Significant growth in power supply needs for electric cooperatives across the country may lead to competition for available funds if funding applications exceed available funds. 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, 2025, we had \$2.8 billion of outstanding loans guaranteed by the Rural Utilities Service and secured under our first mortgage indenture.

Department of Energy

We have a loan guarantee agreement with the Department of Energy, pursuant to which the Department of Energy guaranteed over \$4.6 billion of our eligible costs of construction relating to Plant Vogtle Units No. 3 and No. 4. 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, 2025, we had \$3.9 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.

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 payroll, auditing, human resources, 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, 2025, the balance of the loans outstanding was \$11.3 million.

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, 2025, 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 451 megawatts, bringing the total capacity to more than 1,271 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 experiencing significant load growth, which is projected to continue over the next several years, resulting from native load growth and the development of several large commercial projects, including data centers. 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 are evaluating 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 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, 2025, we had 401 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 2025, we supplied approximately 72% of the retail energy requirements of our members. Our members purchased the remaining 28% 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, 2025, our fleet of generating units totaled 9,317 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, fuel oil and hydro units. Georgia Power, the Municipal Electric Authority of Georgia (MEAG Power) 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, 2025, 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 451 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.

Future Power Resources

Smarr Combined Cycle Generation Facility

We and our members have approved the development and construction of 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 current budget for this project, which includes capital costs, allowance for funds used during construction and a contingency amount, is \$3.3 billion. The projected commercial operation date is 2029. In September 2025, we entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with TIC – The Industrial Company, a subsidiary of Kiewit Energy Group Inc., for the construction of the project. The EPC Agreement is a fixed price agreement with certain limited exceptions that includes performance guarantees and performance liquidated damages and a parent guaranty by Kiewit. We have separately entered into an agreement with GE Vernova Operations, LLC for the purchase of the two combined cycle units. 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. As of December 31, 2025, we had incurred costs of approximately \$343.5 million with respect to this project.

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. In 2025, we entered into a purchase agreement with the equipment manufacturer for the unit and we expect to enter into a construction agreement for the project in 2026. Our current budget 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. As of December 31, 2025, we had incurred costs of approximately \$61.5 million with respect to this project.

Grid Resilience and Innovation Partnerships (GRIP) Program

Oglethorpe and Georgia Transmission Corporation, through the Georgia Environmental Finance Authority, were awarded a grant under the Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program. Oglethorpe's portion of the grant is approximately \$81 million. Oglethorpe expects to use the grant proceeds to support the development of 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 \$240 million, before the application of any grant proceeds. The commercial operation dates for these resources is currently expected to be 2030. We are currently working through the GRIP Program funding process and receipt of any grant proceeds remains 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.

Potential Additional Resources

We and our members are considering capacity upgrades to some of our existing generation resources as well as two additional natural gas-fired resources. One potential new resource is an approximately 713-megawatt, one-unit combined cycle generation facility. Our preliminary cost estimate for this project is approximately \$2.3 billion to \$2.7 billion and the projected commercial operation date is 2033. We are evaluating additional natural gas transportation options in connection with this potential resource. Another potential project is to modify one of our existing facilities by constructing an additional 209-megawatt combustion turbine unit to modernize and replace one or more older units. Our preliminary cost estimate for this modification is approximately \$525 million to 625 million and the projected commercial operation date is 2031. Each of these projects remains subject to meeting the requirements of our wholesale power contracts, including approval from our board and our members' boards and our member subscription process. We expect that this approval process will be completed by summer 2026.

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,	Rayle EMC
Amicalola EMC	an EMC	Satilla Rural EMC
Canoochee EMC	Habersham EMC	Sawnee EMC
Carroll EMC	Hart EMC	Slash Pine EMC
Central Georgia EMC	Irwin EMC	Snapping Shoals EMC
Coastal EMC (d/b/a Coastal Electric Cooperative)	Jackson EMC	Southern Rivers Energy, Inc., an EMC
Cobb EMC	Jefferson Energy Cooperative, an EMC	Sumter EMC
Colquitt EMC	Little Ocmulgee EMC	Three Notch EMC
Coweta Fayette EMC	Middle Georgia EMC	Tri-County EMC
Diverse Power Incorporated, an EMC	Mitchell EMC	Upson EMC
Excelsior EMC	Ocmulgee EMC	Walton EMC
Flint EMC (d/b/a Flint Energies)	Oconee EMC	Washington EMC
Grady EMC	Okefenoke Rural 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. Currently, our members' sales by customer class are approximately one-third to commercial and industrial consumers, of which less than 10% of this consumer class is large data centers, slightly less than two-thirds to residential consumers, and four percent to all other consumers. Our members are the principal suppliers for the power needs of rural Georgia. While our members do not serve any major cities, portions of their service territories are in close proximity to urban areas and have experienced substantial growth over the years due to the expansion of urban areas, including metropolitan Atlanta, into suburban areas and the growth of suburban areas into neighboring rural areas. Each year we file an exhibit containing financial and statistical information for our 38 members for the most recent three year period with our first or second quarter Form 10-Q.

The following table shows the aggregate peak demand and energy requirements of our members for the years 2023 through 2025, and also shows the amount of their energy requirements that we supplied. From 2023 through 2025, peak demand of the members and their energy requirements have fluctuated based on various factors. In July 2025, our member system hit a new summer peak demand of 10,424 megawatts, exceeding our members' prior summer peak of 10,092 megawatts in July 2024. In December 2022, our member system hit its overall peak demand of 10,810 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⁾
2025	10,424	10,424	10,094	45,836,479	33,086,185
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

- (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 and energy we supplied to our own facilities. Excludes test energy supplied to members. Revenue 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 experiencing significant load growth, which is projected to continue 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 "OGLETHORPE POWER CORPORATION – Competition."

Cooperative Structure

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

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

We depend on the revenue we receive from our members pursuant to the wholesale power contracts to cover the costs of 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.

Certain of our members 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 timing and continued availability of Rural Utilities Service funding could also be impacted by federal administrative actions and government shutdowns.

The proposed budget for fiscal year 2026, which began October 2025, includes a loan program level of \$7.0 billion and recent annual appropriations bills have provided the Rural Utilities Service an administrative process through which it may increase available loan funding by up to 25%. Significant growth in power supply needs for electric cooperatives across the country may lead to competition for available funds if funding applications exceed available funds. We cannot predict the amount or cost of Rural Utilities Service loans that may be available to the members in the future. For additional information regarding the Rural Utilities Service, see "OGLETHORPE POWER CORPORATION – Relationship with Federal Lenders – *Rural Utilities Service*."

Members' Relationships with Georgia Transmission and Georgia System Operations

Georgia Transmission provides transmission services to our members for delivery of our members' power purchases from us and other power suppliers. Georgia Transmission and the members have entered into member transmission service agreements under which Georgia Transmission provides transmission service to the members pursuant to a transmission tariff. The member transmission service agreements have a minimum term for network service until December 31, 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 "OGLETHORPE POWER CORPORATION – Relationship with Georgia System Operations Corporation."

Member Power Supply Resources

Oglethorpe Power Corporation

In 2025, we supplied approximately 72% of the retail energy requirements of our members. Pursuant to the wholesale power contracts, we supply each member energy from our generation resources based on its fixed percentage capacity cost responsibility, which are take-or-pay obligations. See "OGLETHORPE POWER CORPORATION – Wholesale Power Contracts." Our members satisfy all of their requirements above their purchase obligations to us with purchases from other suppliers as described below.

Contracts with Southeastern Power Administration

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, 2026, 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, 2025, Green Power EMC purchased energy from 820 megawatts of low-impact hydroelectric, landfill gas and solar facilities, with an additional 451 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 under arrangements with differing terms and durations. All members are parties to requirements contracts or power purchase contracts that meet their incremental requirements.

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

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

REGULATION

Environmental

General

As an electric utility, we are subject to 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. The Environmental Protection Agency, or EPA, finalized a number of rules in 2024 that could impact our power plants; however, in 2025 and early 2026 the Trump administration has issued a number of executive orders and the EPA has initiated rulemakings to 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, in November 2025, filed a motion to vacate the 2024 NAAQS for PM_{2.5}. The court has yet to respond to the motion and we therefore cannot determine the extent, if any, to which EPA's tightening of the PM_{2.5} standard or the outcome of litigation and any future 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 2024 NAAQS for PM_{2.5}, or a future more stringent 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.

Emissions of carbon dioxide from our fossil-fueled power plants totaled 10.8 million metric tons in 2025. Compared to 2005, our overall carbon dioxide emissions rate has declined by 43% 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 2025 declined by 64% compared to 2005.

In May 2024, under the Biden administration, EPA published final rules on "Carbon Pollution Standards" (CPS) 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 2024 CPS 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 2024 CPS, 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. EPA's 2024 CPS is being challenged in the U.S. Court of Appeals for the District of Columbia. However, on March 12, 2025, EPA announced that it would reconsider the 2024 CPS, and the litigation remains in abeyance pending the outcome of EPA's reconsideration.

In January 2025, President Trump signed an executive order withdrawing the United States from the Paris Climate Agreement and any attendant obligations, which became effective in January 2026. In June 2025, under the Trump administration, EPA published a proposed rule that included both a primary proposal to repeal all greenhouse gas standards for power plants, and an alternative proposal to repeal the standards for existing coal-fired plants and the carbon capture and sequestration-based standards for new gas-fired combustion turbines. EPA also requested comment on whether the efficiency and capacity factor standards for new combustion turbines should be modified or repealed. On February 12, 2026, EPA repealed its 2009 endangerment finding for GHG emissions from motor vehicles. This repeal has already been challenged in federal court and it is unclear what effect this repeal might have on the remaining Section 111 emissions standards if the EPA selects the alternative proposal. When finalized, EPA's rule rescinding, revising, or replacing the 2024 CPS is expected to be challenged in federal court. Although we continue to evaluate the impact of federal greenhouse gas regulations on our power plants, we cannot predict the outcome of any regulatory actions or the result of potential litigation challenging any of these actions. 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.

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 revised the original CCR requirements to reflect the different

priorities of subsequent presidential administrations. 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, which EPA now is reconsidering, 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 Plant Scherer to November 1, 2020. In October 2020, EPA published a final rule to moderate the discharge limitations on these two wastestreams. The ELG rule extended 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. 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 CCR and non-CCR 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 rule is being challenged in the U.S. Appeals Court for the District of Columbia. In 2025, the Trump administration issued executive orders directing 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, and litigation is being held in abeyance while EPA reconsiders the rule. As of December 2025, EPA has finalized extensions of certain compliance deadlines and is expected to address additional requirements in the future. 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 remediating 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. On March 6, 2025, EPD issued a final permit for Plant Wansley to close the ash pond by removing the coal ash. 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. Additionally, 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 plan for Plant 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. However, the litigation is being held in abeyance as EPA reconsiders the 2024 legacy CCR rule consistent with the Trump administration's 2025 executive orders. EPA's future actions could affect both the determinations and regulatory requirements. On February 6, 2026, EPA published a final rule extending certain compliance deadlines and is expected to address additional requirements of the legacy CCR rule in the future. At this time, it is unclear what additional regulatory actions EPA will take or whether such actions will affect the current closure plan at Plant Scherer or CCR management requirements 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 \$270 million for conversion to dry ash handling, landfill construction, and wastewater treatment. This estimate includes approximately \$200 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 \$107 million of this amount has already been incurred. See Note 1 of Notes to Consolidated Financial Statements. 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.

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

As a co-owner of Plants Hatch and Vogtle, 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 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. For information regarding the Nuclear Regulatory Commission's regulation relating to decommissioning of nuclear facilities and regarding the Department of Energy's assessments pursuant to the Energy Policy Act for decontamination and decommissioning of nuclear fuel enrichment facilities, see Note 1 of Notes to Consolidated Financial Statements.

Federal Power Act

General

Pursuant to the Federal Power Act, 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. On January 16, 2026, FERC issued a revised procedural schedule indicating that it would begin its environmental review in May 2026. 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 cybersecurity elements designed to protect and preserve our critical information and energy infrastructure systems. Although we intend to comply with all currently effective and enforceable reliability standards, we cannot provide assurance that we will always be in compliance. We are obligated to maintain and retain evidence of compliance with specific requirements. SERC Reliability Corporation also regularly monitors us for compliance with reliability standards. We expect that existing reliability standards will continue to be refined and that new reliability standards will be developed or adopted.

ITEM 1A. RISK FACTORS

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

Facility Ownership, Operation and Construction Risk Factors

We are subject to construction risks for 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 current budget for this project, which includes capital costs, allowance for funds used during construction and a contingency amount, is \$3.3 billion. The projected commercial operation date is 2029. In September 2025, we entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with TIC – The Industrial Company, a subsidiary of Kiewit Energy Group Inc., for the construction of the project. The EPC Agreement is a fixed price agreement with certain limited exceptions that includes performance guarantees and performance liquidated damages and a parent guaranty by Kiewit. We have separately entered into an agreement with GE Vernova Operations, LLC for the purchase of the two combined cycle units. As of December 31, 2025, we had incurred costs of approximately \$343.5 million with respect to this project. The other project is an approximately 240-megawatt combustion turbine unit to be constructed at our Talbot Energy Facility. Our current budget for this unit is approximately \$360 million and, as of December 31, 2025, we had incurred costs of approximately \$61.5 million with respect to this project. In 2025, we entered into a contract for the combustion turbine unit and we expect to enter into a construction agreement for the project in 2026. The projected commercial operation date for the Talbot project 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 date is currently projected to be 2030. Our cost estimate of these battery storage resources is approximately \$240 million, before the application of any grant proceeds. 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. We are currently working through the GRIP Program funding process and receipt of any grant proceeds remains 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 are considering capacity upgrades to some of our existing generation resources as well as two additional natural gas-fired resources. One potential new resource is an approximately 713-megawatt, one-unit combined cycle generation facility. Our preliminary cost estimate for this project is approximately \$2.3 billion to \$2.7 billion and the projected commercial operation date is 2033. We are evaluating additional natural gas transportation options in connection with this potential resource. Another potential project is to modify one of our existing facilities by constructing an additional 209-megawatt combustion turbine unit to modernize and replace one or more older units. Our preliminary cost estimate for this modification is approximately \$525 million to 625 million and the projected commercial operation date is 2031. Each of these projects remains subject to meeting the requirements of our wholesale power contracts, including approval from our board and our members' boards and our member subscription process. We expect that this approval process will be completed by summer 2026.

In addition to load growth, winter planning reserve requirements are increasing in Georgia to provide greater margin against the impact of severe winter weather, and we have also made significant capital investments in certain of our generation resources to add dual-fuel capabilities to minimize the operational risk of our resources during a severe winter event. We expect that these increased reserve requirements that may contribute to generation resource development.

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 are also subject to construction risks for capital projects to upgrade our existing facilities and 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 engineering, procurement and construction contractors and 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 or tariff uncertainty;
- 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 2025.

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 attract and 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, freezing weather events, 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 "BUSINESS—OGLETHORPE POWER CORPORATION—Relationship with Georgia Power Company" and "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, fuel oil and coal, and our agent obtains uranium for our co-owned nuclear facilities, from various suppliers. Any disruptions in these 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. Some 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 agent's 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 experiencing significant load growth, which is projected to continue over the next several years, which may present risks to the electric system in Georgia and our members.

Georgia is experiencing significant load growth, which is projected to continue 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. In Georgia, loads of 900 kilowatts or more are subject to competition at initial operation, and some of our members are competing for these loads. 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 in Georgia is putting pressure on existing generation and transmission infrastructure and will require significant investment to meet anticipated demand. Members who serve large data centers may face increased counterparty risk, as these customers may constitute a disproportionate percentage of their electricity sales, which have historically been primarily residential. Technological changes could alter the development and continued resource needs of

data centers, and any significant decrease in those needs could affect a counterparty's ability or willingness to pay for large electricity commitments. Additionally, the rapid growth in datacenters in Georgia has led to certain local and state efforts to slow down and potentially limit data center growth. Changes in local or state law could also affect the development of current or proposed data centers which may change current growth projections.

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 our members may seek additional generation from us or other third parties. If our members' actual load growth and continued demand is significantly lower than projected, additional power purchase obligations provided by us or other third parties could increase certain members' cost of electric service 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, 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 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 and represented 10% of the energy we sold to our members in 2025. The percentage of gross energy generated by coal-fired resources we sell to our members has decreased from 45% in 2008 to 10% in 2025. Utilization of coal-fired generation resources is largely dependent on the relative price to generate energy compared to other available generation resources, particularly natural gas-fired resources. In addition, potential new environmental standards could require additional capital expenditures or operating costs that make continued operation of our remaining units at Plant Scherer uneconomical. In recent years, 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 Plant Scherer units could require us to recover the undepreciated costs for the units 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 interests 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 projected load growth in Georgia, was extending commercial operation of Scherer Unit No. 3 to 2038. 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 have relied on federal loan programs guaranteed by the Rural Utilities Service, a branch of the U.S. Department of Agriculture, in order to meet a significant portion of our long-term financing needs, typically at a cost that was lower than traditional capital markets financing. We have applied 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 and expect to apply for Rural Utilities Service funding for eligible future generation resources and capital projects. 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. Additionally, significant growth in power supply needs for electric cooperatives across the country may lead to competition for available funds if funding requests exceed available funding. The timing and continued availability of Rural Utilities Service funding could also be impacted by federal administrative actions or government shutdowns. 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 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. 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. 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. We are continuing to work through the funding process under the GRIP Program and receipt of funds remains subject to meeting applicable program requirements.

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 expect to seek additional medium-term liquidity to provide interim financing for the Smarr combine cycle project, and other capital projects and system investments pending the availability of long-term financing. We believe that we will be able to maintain sufficient access to the capital markets based on our current credit ratings. However, our credit ratings reflect the views of the rating agencies, which could change at any point in the future. 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, certain 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 \$3.6 billion of natural gas resources for our members and may pursue additional generation projects or uprates to our existing facilities. These projects follow the recent completion of Vogtle Units No. 3 and No. 4, for which we added \$8.6 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, 2025, we had \$12.6 billion of long-term debt outstanding. As a result of these resource additions, through 2024, our debt increased as a percentage of our total capitalization, which 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.

We are also required to maintain a minimum 1.10 margins for interest ratio under our first mortgage indenture. For most of the development and construction period for the Vogtle units, our board of directors approved budgets to achieve a margins for interest ratio of 1.14 to increase financial coverage during that period of generation expansion. In each of those 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 and is maintaining this level for 2026. We believe that the 1.10 margins for interest ratio is sufficient to allow us to continue to meet our current and projected debt obligations. However, beginning another period of generation expansion with our 1.10 margins for interest ratio may put continued pressure on certain of our financial metrics.

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, fuel oil, coal and uranium. Our primary fuel price exposure is to natural gas and, for 2025, natural gas expenses constituted 69% 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 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 may expose them to increased counterparty risk, potentially 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 to minimize rate increases 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 federal environmental regulatory landscape shifted significantly during 2025 and early 2026. The Trump administration issued several executive orders addressing environmental regulations and the EPA took actions that affected existing environmental regulations, and proposed new or replacement regulations in several areas. The ultimate impact of litigation challenging EPA rules finalized prior to 2025, and the impact of EPA's actions and replacement rules, including litigation challenging such actions, is uncertain.

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.

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 \$270 million, of which approximately \$200 million had been spent as of December 31, 2025. Expenditures for the settlement of related asset retirement obligations, including coal ash disposal, at our operating and retired coal plants are approximately \$600 million to \$800 million (in year of expenditure dollars), approximately \$107 million of which had been spent as of December 31, 2025. If Georgia's requirements for coal ash disposal at Plant Scherer are subsequently revised or the proposed closure plans are not approved, our estimated compliance costs could increase materially. 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 “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.

Despite the current presidential administration, concerns regarding climate change remain prevalent and future 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. However, recent actions by the executive branch have created significant uncertainty regarding EPA’s greenhouse gas regulations applicable to our resources.

In May 2024, EPA published final rules to 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 under the Paris Climate Agreement. As written, EPA’s 2024 final rule addressing greenhouse gases 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. This rule was immediately challenged and continues to be the subject of litigation in the U.S. Court of Appeals for the District of Columbia.

In January 2025, President Trump signed an executive order withdrawing the United States from the Paris Climate Agreement and any attendant obligations, which became effective in January 2026. In June 2025, EPA published a proposed rule that included both a primary proposal to repeal all greenhouse gas standards for power plants, and an alternative proposal to repeal the standards for existing coal-fired plants and the carbon capture and sequestration-based standards for new gas-fired combustion turbines. In February 2026, the EPA repealed its 2009 endangerment finding for greenhouse gases for motor vehicles although it is unclear what effect the repeal might have on EPA’s forthcoming final rule. Although we continue to evaluate the impact of EPA’s greenhouse gas rules on our power plants, we cannot predict the outcome of any regulatory actions or the result of potential litigation challenging any of these actions. Even if finalized, regulatory environmental policies are subject to change based on the priorities of the then-current administration, which creates uncertainty and unpredictability for longer-term planning.

Federal and state legislative and regulatory efforts to limit greenhouse gas emissions for motor vehicles, including carbon dioxide, and reduce the potential impacts of climate change 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 advanced information technology systems and network infrastructure. Because our generation resources are part of broader interconnected systems that constitute a 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, generation resource development and construction, equipment manufacturing, natural gas pipelines, co-owner agreements, contracts related to the market price and supply of natural gas and coal, power sales and purchases and parent guarantees. 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 development, construction and equipment manufacturing agreements, 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. We have remarketing agreements in place for certain of our variable rate bonds and if a particular series of new debt securities is offered through underwriters, those underwriters may attempt to make a market in the debt securities. Dealers or underwriters have no obligation to make a market in any of our debt securities and may terminate any market-making activities at any time, for any reason, without notice. Further, removal from any index may

have an adverse effect on the liquidity of the trading market, if any, for our debt securities removed from that index. As a result, we cannot provide any assurance as to the liquidity of any trading market for our debt securities, the ability of holders to sell their debt securities or the price at which holders will be able to sell their debt securities.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Risk Management and Strategy

Our generating facilities are part of the United States' energy infrastructure system and we face a myriad of cybersecurity threats. As such, cybersecurity is an area of continuous focus and we maintain a comprehensive cybersecurity risk management program with processes in place to assess, identify and manage cybersecurity risks. Our management and oversight of direct and indirect cybersecurity risks and our response to any cybersecurity incident is an integral part of our business.

We have a long-standing focus on cybersecurity risks and compliance with applicable safety protocols. Our primary cybersecurity focus areas are plant infrastructure, data privacy, and outsourced services. Within these areas, we maintain multi-faceted, layered security programs designed to protect and preserve the confidentiality, integrity and availability of data and systems. Within our organization, we have a mature information technology security program and cybersecurity responsibilities are clearly defined. We regularly invest in technology and information system upgrades designed to prevent, detect and respond to attacks. We also perform tabletop exercises for executive leadership.

We require all employees to complete quarterly cybersecurity-related training and awareness programs. We review the cybersecurity practices of our vendors who provide goods and/or services that could impact our plant control systems and require contractors with access to our plant control rooms to complete annual cybersecurity-related training. We also require enhanced diligence reviews on all contractors and employees who have access to our plant control systems.

As part of the nation's critical infrastructure network, we are subject to certain mandatory reliability standards, which include cybersecurity requirements. We have a formal compliance program to establish, monitor and maintain compliance that includes comprehensive cybersecurity elements designed to protect and preserve our critical information and energy infrastructure systems. We reference industry and government frameworks and best practices to continuously improve our cybersecurity program and we participate in industry groups and information sharing exchanges to understand emerging cybersecurity trends and threats.

Georgia Transmission and Georgia System Operations provide us with certain transmission and system operations services that enable us to deliver energy to our members. As part of our risk management approach, we coordinate our cybersecurity preparedness and response planning with Georgia Transmission and Georgia System Operations.

As part of our approach to cyber risk management, we regularly perform internal audits of internal processes and controls relating to cybersecurity to assess and enhance the effectiveness of our security programs. From time to time, as appropriate under our overall cybersecurity program, we engage third-party experts to support and audit our cybersecurity preparedness. We have also adopted cybersecurity incident response guidelines. As required by these guidelines, teams and plans are in place to respond to any cybersecurity incident, including internal and external communication responsibilities.

As of the date of this annual report, we have not experienced any cybersecurity incident that has materially affected our business. See "RISK FACTORS" for a discussion of cybersecurity risks that may affect us.

Governance

Our board of directors, along with the audit committee of our board of directors, is responsible for oversight of our cybersecurity risks and receives regular reports regarding our assessment and management of cybersecurity risks and information regarding any significant cybersecurity incidents.

Our board has adopted a policy regarding cybersecurity and delegated administration of the policy to our President and Chief Executive Officer.

Currently, our 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, assesses and monitors material risks from cybersecurity threats. Members of our risk management and compliance committee receive regular updates regarding the prevention, mitigation, and detection of cybersecurity incidents and would oversee the response and remediation of any material cybersecurity incident. Our risk management and compliance committee also ensures our board of directors is briefed on cybersecurity risks, makes materiality determinations with regards to cybersecurity risks and monitors the active management of cybersecurity risks by internal and external teams. For additional information regarding our board of directors' risk oversight activities, see "DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE – Board of Directors' Role in Risk Oversight."

ITEM 2. PROPERTIES

Generating Facilities

As of December 31, 2025, we owned, leased or had undivided percentage interests in the generating facilities identified in the table below. Substantially all of our interests in these facilities or agreements, as applicable, are subject to the lien of the first mortgage indenture.

Facilities	Type of Fuel	Percentage Interest	Our Summer Planning Reserve Capacity ⁽¹⁾ (megawatts)	Commercial Operation Date	License Expiration Date
Plant Hatch (near Baxley, GA)					
Unit No. 1	Nuclear	30	262.2	1975	2034
Unit No. 2	Nuclear	30	264.3	1979	2038
Plant Vogtle (near Waynesboro, GA)					
Unit No. 1	Nuclear	30	344.5	1987	2047
Unit No. 2	Nuclear	30	344.7	1989	2049
Unit No. 3	Nuclear	30	334.5	2023	2062
Unit No. 4	Nuclear	30	334.5	2024	2063
Plant Scherer (near Forsyth, GA)					
Unit No. 1	Coal	60	515.0	1982	N/A ⁽²⁾
Unit No. 2	Coal	60	515.0	1984	N/A ⁽²⁾
Rocky Mountain (near Rome, GA)					
Units No. 1-3	Pumped Storage Hydro	74.61	816.9	1995	2026 ⁽³⁾
Baconton (near Baconton, GA)					
Unit 500	Gas-Oil	100	44.3	2000	N/A ⁽²⁾
BC Smith (near Savannah, GA)					
Unit No. 1	Gas	100	527.0	2003	N/A ⁽²⁾
Chattahoochee (near Carrollton, GA)					
Unit No. 1	Gas	100	484.5	2003	N/A ⁽²⁾
Doyle (near Monroe, GA)					
Units No. 1-5	Gas	100	272.1	2000	N/A ⁽²⁾
Hartwell (near Hartwell, GA)					
Units No. 1-2	Gas-Oil	100	304.9	1994	N/A ⁽²⁾
Hawk Road (near Franklin, GA)					
Units No. 1-3	Gas	100	478.2	2001	N/A ⁽²⁾
Talbot (near Columbus, GA)					
Units No. 1-4	Gas-Oil	100	449.6	2002	N/A ⁽²⁾
Units No. 5-6	Gas-Oil	100	226.0	2003	N/A ⁽²⁾
TA Smith (near Dalton, GA)					
Units No. 1-2	Gas	100	1,294.6	2002	N/A ⁽²⁾
Walton County (near Monroe, GA)					
Units No. 1-3	Gas	100	449.7	2001	N/A ⁽²⁾
Washington County (near Sandersville, GA)					
Units No. 2-3	Gas-Oil	100	326.0	2003	N/A ⁽²⁾
TOTAL			8,588.5		

- (1) Summer Planning Reserve Capacity is the amount used for 2026 capacity reserve planning for the specified resources. Megawatt amounts in this table represent our portion of the total capacity at each facility based on our percentage interest.

- (2) 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.
- (3) In 2024, we submitted an application for a new license with FERC. The FERC may set a new license term for between 30-50 years, with FERC's default being 40 years.

Fuel Supply

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

Coal. Coal for Scherer Units No. 1 and No. 2 is purchased under term contracts and in spot market transactions. As of February 28, 2026, our coal stockpile at Plant Scherer contained a 38 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, 2025, we leased approximately 709 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 our natural gas-fired generation resources. We purchase natural gas in the spot market and under longer-term agreements at daily 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 Power, 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
	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 Power	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 530 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 Power and two municipalities. Georgia Power is the largest supplier of electric energy in the State of Georgia. See "BUSINESS – OGLETHORPE POWER CORPORATION – Relationship with Georgia Power Company." Georgia Power is subject to the informational requirements of the Exchange Act, and, in accordance therewith, files reports and other information with the SEC.

Municipal Electric Authority of Georgia

The Municipal Electric Authority of Georgia, also known as MEAG Power, is a state-chartered, municipal joint-action agency that provides capacity and energy to its membership of 49 municipal electric utilities, including 48 cities and one county in the State of Georgia. MEAG Power has wholesale take-or-pay power sales contracts with each of its participants. MEAG Power is Georgia's third largest power supplier behind Georgia Power and us.

City of Dalton, Georgia

Dalton Utilities is a combined utility that provides electric, gas, water and wastewater services to the city of Dalton, located in northwest Georgia, and some of the surrounding communities.

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 Power 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 Power, the City of Dalton and us. The parties to each Ownership Agreement and Operating Agreement are referred to as "participants" with respect to each such agreement.

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 Power and the City of Dalton entered into amendments to the Operating Agreement for Plant Vogtle and the Nuclear Managing Board Agreement, and entered into an Ownership Agreement that governs participation in Vogtle Units No. 3 and No. 4. Pursuant to this ownership agreement, Georgia Power has designated Southern Nuclear as its agent for licensing, engineering, procurement, 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 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 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, 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 Power) 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 "BUSINESS – REGULATION – Nuclear Regulation." The Operating Agreement for Scherer Units No. 1 and No. 2 expires on January 31, 2028 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.

The Georgia Public Service Commission has approved Georgia Power's proposed upgrades to Plant Vogtle Units No. 1 and No. 2, which would be available in 2029 through 2031, that would increase our nameplate capacity by an aggregate of approximately 30 megawatts (based on our 30% interest).

Rocky Mountain

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

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

ITEM 3. LEGAL PROCEEDINGS

See Note 12 of Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Not applicable.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents 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, 2025, 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 the "FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA."

	(dollars in thousands)		
	2025	2024	2023
STATEMENTS OF REVENUES AND EXPENSES DATA			
Operating revenues:			
Sales to members	\$ 2,442,690	\$ 2,145,522	\$ 1,681,566
Sales to non-members	98,502	36,325	58,619
Operating expenses	\$ 2,004,647	\$ 1,698,351	\$ 1,463,119
Other income, net	\$ 44,482	\$ 67,390	\$ 81,049
Net interest charges	\$ 525,672	\$ 480,385	\$ 292,325
Net margin	\$ 55,355	\$ 70,501	\$ 65,790
BALANCE SHEET DATA			
Assets:			
Construction work in progress	\$ 787,886	\$ 320,167	\$ 3,294,641
Total electric plant	\$ 13,228,914	\$ 12,712,076	\$ 12,680,395
Total assets	\$ 17,149,799	\$ 16,477,538	\$ 16,524,851
Capitalization:			
Patronage capital and membership fees	\$ 1,383,773	\$ 1,328,418	\$ 1,257,917
Long-term debt and obligations under finance leases	12,599,232	12,686,674	12,149,489
Obligation under Rocky Mountain transactions	34,099	31,910	29,862
Other	5,284	5,715	5,152
Total long-term debt and equities	<u>\$ 14,022,388</u>	<u>\$ 14,052,717</u>	<u>\$ 13,442,420</u>
Less: Long-term debt and finance leases due within one year	391,726	398,979	384,426
Less: Unamortized debt issuance costs and bond discounts	120,065	120,328	120,560
Total capitalization	\$ 13,510,597	\$ 13,533,410	\$ 12,937,434
OTHER DATA			
Megawatt hours sold to members ⁽¹⁾	33,086,185	31,001,082	28,289,147
Member energy requirements (MWh) ⁽²⁾	45,836,479	44,245,782	41,370,456
Percentage of Member energy requirements supplied	72 %	70 %	68 %
Member revenues per kWh sold	7.38 ¢	6.92 ¢	5.94 ¢
Equity Ratio ⁽³⁾	9.9 %	9.5 %	9.4 %
Margins for Interest Ratio ⁽⁴⁾	1.10	1.14	1.14

(1) Includes energy supplied to members for resale at wholesale and energy we supplied to our own facilities. Excludes test energy supplied to members. Revenues and costs associated with test energy were capitalized.

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

(3) 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.

(4) 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 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 and 2026, 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.

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

Executive Overview

General

Consistent with our cooperative mission, our principal business is providing wholesale electric service to our 38 members in a reliable, safe and cost-effective manner. In 2025, we served 72% of our members' power supply needs from our diverse portfolio of generating units that totals 8,589 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 which provides revenue stability to support our members' long-term power supply needs. To that end, our rate structure provides for a pass-through of actual energy costs to our members. 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 established based on an annual budget, and are allocated to our members regardless of energy usage. This budget may be adjusted throughout the year to ensure full cost recovery and margin coverage. 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.

2025 Financial Results

We had another successful year in 2025 and continue to be well positioned, both financially and operationally, to fulfill our obligations to our members, bondholders and creditors.

In 2025, our operating revenues increased to \$2.5 billion, and we sold over 33.0 million megawatt hours to our members compared to \$2.2 billion in revenues and 31.0 million megawatt hours sold to our members in 2024. In 2025, our revenues were sufficient to recover all of our costs and to satisfy our debt service obligations and financial covenants. Specifically, we recorded a net margin of \$55.4 million in 2025, which achieved the 1.10 margins for interest ratio as approved by our board of directors and is required to meet the rate covenant under our first mortgage indenture. For 2026, our board of directors has approved a budgeted margins for interest ratio 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 in 2024 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, 2025, our total assets were \$17.1 billion and total long-term debt was \$12.6 billion. We are also in the process of developing and constructing additional generation resources on behalf of our members which will continue to increase our total 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. This has enabled us to borrow long-term debt at relatively low rates and our weighted average interest cost on long-term debt was 4.07% per annum at December 31, 2025. 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.

Fiscal year 2025 represented the first year in which the costs of both Vogtle Unit No. 3 and Unit No. 4 were reflected in member rates for the entire year. Even including costs related to the new Vogtle units, our average wholesale power cost to our members remained below 7.5 cents per kilowatt hour in 2025. Fiscal year 2025 was also the first year our target margins for interest ratio returned to the pre-construction level of 1.10. Consequently, our 2025 financial results represent a normalized operating profile under our cost-plus formulary rate structure and serves as a relevant baseline for our long-term financial planning. Following the completion of the Vogtle units, we are continuing to advance additional generation projects to meet our members' projected needs.

New Resources to Meet Member Demand

Georgia is experiencing significant load growth, which is projected to continue over the next several years. This growth is a result of native load growth and the development of several large commercial projects, including data centers. In addition to load growth, our member demand has experienced an increase in winter peaks which, in connection with increasing winter capacity reserve requirements, has created the need for additional natural gas resources that can reliably provide energy during severe winter events and particularly when solar resources are not generating electricity. One way to improve winter reliability is to add dual-fuel capability to combustion turbine units.

As a result of these factors, we are developing and constructing two new natural gas-fired generation resources for our members. 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 current budget for this project, which includes capital costs, allowance for funds used during construction and a contingency amount, is \$3.3 billion. During 2025, we entered into key construction and procurement contracts to proceed with the development and construction of this project, and our projected commercial operation date is in 2029. As of December 31, 2025, we had incurred costs of approximately \$343.5 million with respect to this project. The other natural gas project is an approximately 240-megawatt combustion turbine unit to be constructed at our Talbot Energy Facility in Talbot County, Georgia. Our current budget for this project is approximately \$360 million and, as of December 31, 2025, we had incurred costs of approximately \$61.5 million with respect to this project. In 2025, we entered into an agreement for the combustion turbine unit and expect to enter into a construction agreement in 2026. Our projected commercial operation date for the Talbot unit is in 2029. The new Talbot unit will be constructed with dual-fuel capabilities. This will complement our 2025 investments in dual-fuel upgrades to the existing Talbot and Washington County combustion turbine units, which now provide us a total of 11 combustion turbine units with dual-fuel capabilities.

We and our members have also approved 75 megawatts of utility-scale battery storage resources. Our budget for these batteries is approximately \$240 million which is expected to be offset by an \$81 million grant awarded under the Department of Energy's GRIP Program. We are continuing to work through the funding process under the GRIP Program and receipt of funds remains subject to meeting applicable program requirements. Our projected commercial operation dates for these battery storage resources is in 2030.

In addition to these approved projects, we and our members are considering capacity upgrades to some of our existing generation resources as well as two additional natural gas-fired resources. One potential new resource is an approximately 713-megawatt, one-unit combined cycle generation facility. Our preliminary cost estimate for this project is approximately \$2.3 billion to \$2.7 billion and the projected commercial operation date is 2033. We are evaluating additional natural gas transportation options in connection with this resource. Another potential project is to modify one of our existing facilities by constructing an additional 209-megawatt combustion turbine unit to modernize and replace one or more older units. Our preliminary cost estimate for this modification is approximately \$525 million to \$625 million and the projected commercial operation date is 2031. Each of these projects remains subject to meeting the requirements in our wholesale power contracts, including approvals from our board and our members' boards and our member subscription process. We expect that this approval process will be completed by summer 2026.

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 extends through May 2029 and supports our commercial paper program. Additionally, we have three other bank credit facilities which provide another \$450 million in credit commitments. In order to maintain strong liquidity levels, and support our capital program, we are evaluating additional intermediate-term financing over the next two years, which may consist of bank term loans and/or bond offerings, subject to market conditions. These financings are expected to provide construction-period funding for new generation resources, capital improvements to existing facilities, and general corporate purposes, including refinancing of interim borrowings.

Beyond our liquidity resources, 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 \$3.9 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, fuel oil and hydro resources, and complying with environmental regulations presents substantial challenges for us and 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.

In 2025 and early 2026, presidential executive orders and EPA actions significantly changed the federal environmental regulatory landscape. In addition to other actions, EPA's repeal of the 2009 endangerment finding for greenhouse gas emissions for motor vehicles in February 2026 has the potential to significantly change greenhouse gas regulations that apply to our fossil-fuel generation resources. At this time, the future of federal environmental regulations 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. Regardless as to the outcome of current regulatory proposals and rules, 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.

Despite this uncertainty, 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.

Commitment to our Members

As an electric cooperative, we are committed to sustainable and long-term success for the benefit of our members and the people and businesses they serve. 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.

Outlook for 2026

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. 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, fuel oil 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;
- developing and constructing additional generation resources to enable our members to meet the energy requirements stemming from load growth in their service territories; 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 require 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 could materially impact our results of operations and financial condition. 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, 2025, our regulatory assets and regulatory liabilities totaled \$1.0 billion and \$869.9 million, respectively. Application of regulated operations accounting is based on management's assessment that it is probable that these costs will be recovered from members through future revenues under our wholesale power contracts. If events such as increased competition, changes in regulation, or other factors were to occur that would make recovery no longer probable, we could no longer apply the provisions of accounting for regulated operations. This would require us to eliminate all regulatory assets and regulatory liabilities from our consolidated balance sheet, resulting in a critical change in how we recognize our revenues and expenses. 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 and closure costs 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, estimating the decommissioning and closure costs, and evaluating how costs will escalate with inflation. Actual results may differ from our estimates. At December 31, 2025, approximately 94% of our total asset retirement obligations related to our nuclear decommissioning and coal ash pond closure obligations. For additional details regarding our asset retirement obligations, see Note 1h of Notes to Consolidated Financial Statements.

Nuclear Decommissioning Obligations. Given its significance, we consider our nuclear decommissioning liabilities critical estimates. At December 31, 2025, our nuclear decommissioning related asset retirement obligation was \$851.8 million. Decommissioning cost studies for Plants Hatch and Vogtle are performed periodically to provide updated site-specific "base year" cost estimates used 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. These significant assumptions are evaluated at least annually and updated as necessary based on current information. In evaluating these assumptions, management considers factors including, but not limited to, the nuclear units' remaining licensed and economic lives, re-licensing expectations, regulatory requirements, economic considerations and industry trends. 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. No significant changes in cash flow estimates were recorded in 2025. Changes in these assumptions, including those related to regulatory requirements or the nuclear regulatory environment, could materially affect the measurement of the related asset retirement obligation and the amount and timing of future depreciation expense associated to amounts capitalized as part of the related long-lived assets.

Coal Ash Pond Closure Obligations. We also consider our coal ash pond closure liabilities to be critical estimates. At December 31, 2025, our coal ash related asset retirement obligation was \$356.5 million. Cost studies are periodically performed to provide site-specific "base year" estimates that determine the nature and timing of planned closure 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 closure and post-closure activities, timing of future cash outlays, and the selection of cost escalation and discount rates. Estimates are sensitive to changes in federal and state environmental regulations, including coal combustion residual requirements. These significant assumptions are evaluated at least annually and updated as necessary based on current information, including regulatory developments, site conditions and economic factors. Our current estimates are based upon studies that were performed in 2025. For ratemaking purposes, we apply regulated operations accounting to the closure costs and expect to recover ash pond closure costs through rates. Changes in these assumptions or in regulatory requirements could materially affect the measurement of the related asset retirement obligation and the amount and timing of future depreciation expense associated to amounts capitalized as part of the related long-lived assets.

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 "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture" for a discussion of how we calculate our margins for interest ratio.

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

Prior to 2009, we budgeted and achieved annual margins for interest ratios of 1.10, the minimum required by the first mortgage indenture. To enhance margin coverage during a period of increased capital requirements, our board of directors has approved budgets with margins for interest ratios that exceeded 1.10. Since 2010, we have achieved our board approved margins for interest ratio of 1.14. 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, 2025, we had \$1.4 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 9.9% and 9.5% at December 31, 2025 and 2024, 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 "BUSINESS – OGLETHORPE POWER CORPORATION – First Mortgage Indenture" for a discussion regarding limitations on distributions under our first mortgage indenture.

Rate Regulation

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

Tax Status

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

Results of Operations

Factors Affecting Results

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

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 2025, the amount of energy we supplied to our members and the percentage of our members' overall load continued to increase. One of the primary reasons for this growth was that 2025 was the first full year that both Vogtle Units No. 3 and No. 4 were operational. We are continuing to develop additional resources for our members with the development and construction of the Smarr combined cycle and Talbot Unit No. 7 projects, which increased our construction work in progress in 2025.

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.

Over the past few years, weather has been a significant factor. The summer experienced extremely hot weather in 2025. Based on meter readings, our member system hit a new summer peak demand of 10,424 megawatts in July 2025, exceeding both our members' prior summer and winter peaks of 10,092 and 10,236 megawatts, respectively in 2024. In 2024, the summer experienced extremely hot weather and winter was below normal and, in 2023, the summer experienced extremely hot weather. As a result, the amount of energy (in megawatt-hours) we generated and sold to members was higher than in 2024 and 2023. The higher sales was provided by an increase in nuclear generation and higher utilization our combined cycles generating facilities and our coal facility and our simple cycle combustion facilities.

In addition to member demand, we sell power from BC Smith, Baconton, Washington County, and Walton County off-system. We acquired these resources 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. At December 31, 2025, the deferral periods for Baconton and Washington County ended. BC Smith and Walton County's deferral periods are expected to end November 2026 and December 2027, respectively. 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 2025 and 2023.

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. Higher average natural gas prices as well as a full year of operation at Vogtle 3&4 contributed to the increase in fuel costs and megawatt-hour sales to the members in 2025. In 2024, 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 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 2025, generation from our combined cycle units was

higher compared to 2024 when two of our combined cycle units underwent major maintenance outages. These outages also resulted in lower generation from our combined cycle units in 2024 compared to 2023.

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 and 2025, generation from the new units at Plant Vogtle offset the temporary decrease in generation from refueling outages at other units at Plant Hatch and Plant Vogtle.

We also continued to make significant capital investments over the past three years. Some of our main investments have been for (i) the new units at Plant Vogtle, (ii) the Baconton and Walton County acquisitions and (iii) dual fuel projects at Talbot and Washington County, which were completed and placed in-service in December 2025. We have primarily financed these capital expenditures with debt. This 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 notwithstanding a decrease from 2024 to 2025 as we lowered our targeted margins for interest ratio from 1.14 to 1.10 in 2025.

Net Margin

Our net margin for the years ended December 31, 2025, 2024 and 2023 was \$55.4 million, \$70.5 million and \$65.8 million, respectively. These amounts produced a margins for interest ratio of 1.10 for 2025 and 1.14 for 2024 and 2023. For additional information on our margin requirement, see "— Summary of Cooperative Operations – *Margins.*"

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)			2025 vs. 2024	2024 vs. 2023
	2025	2024	2023	% Change	% Change
Capacity revenues	\$ 1,603,888	\$ 1,501,903	\$ 1,082,368	6.8 %	38.8 %
Energy revenues	838,802	643,619	599,198	30.3 %	7.4 %
Total	\$ 2,442,690	\$ 2,145,522	\$ 1,681,566	13.9 %	27.6 %
kWh Sales to members ⁽¹⁾	33,086,185	31,001,082	28,289,147	6.7 %	9.6 %
Cents/kWh	7.38	6.92	5.94	6.7 %	16.5 %
Member energy requirements supplied ⁽¹⁾	72 %	70 %	68 %	2.9 %	2.9 %

⁽¹⁾ Includes energy supplied to members for resale at wholesale and energy we supplied to our own facilities. Excludes test energy supplied to members. Revenues and costs associated with test energy were capitalized.

Capacity revenues increased in 2025 compared to 2024 primarily due to a full year of operation of Plant Vogtle Unit No. 4 and the Walton resource we acquired in 2024 and the related recovery of net interest and depreciation expense. The increase in capacity revenues in 2024 compared to 2023 was due primarily to Plant Vogtle Unit No. 4 being placed in service

in April 2024 and the related recovery of net interest and depreciation expense. For a discussion of production costs and depreciation expense, see “— *Operating Expenses*.”

The 30.3% increase in energy revenues from members in 2025 compared to 2024 was primarily a result of an increase in our average cost of energy and a 6.8% increase in generation for member sales. 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. For a discussion of fuel expense, see “— *Operating Expenses*.”

Sales to non-members. In 2025 and 2024, 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 increased in 2025 from 2024 due to an increase in fuel costs for natural gas and an increase in megawatt-hours sold. 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. In 2024 and 2023, 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. This tolling agreement with Georgia Power expired in May 2024.

Sales to non-members were as follows:

(in thousands)				
	2025	2024	2023	
Energy revenues	\$ 98,502	\$ 34,753	\$ 44,995	
Capacity revenues	—	1,572	13,624	
Total	\$ 98,502	\$ 36,325	\$ 58,619	
kWh Sales to non-members	2,151,506	1,048,865	1,415,042	
Cents/kWh	4.58	3.46	4.14	

Operating Expenses

Our operating expenses increased 18.0% in 2025 compared to 2024 primarily due to significantly higher fuel costs, higher depreciation and amortization expenses, higher purchased power costs and higher production costs. Our operating expenses increased 16.1% in 2024 compared to 2023 primarily due to significantly higher production costs and higher depreciation and amortization expenses.

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

Fuel Source	Cost			Generation ⁽¹⁾						Cents per kWh					
	(dollars in thousands)			(kWh in thousands)											
	2025	2024	2023	2025 vs. 2024 % Change	2024 vs. 2023 % Change	2025	2024	2023	2025 vs. 2024 % Change	2024 vs. 2023 % Change	2025	2024	2023	2025 vs. 2024 % Change	2024 vs. 2023 % Change
Coal	\$ 139,399	\$ 138,682	\$ 124,638	0.5 %	11.3 %	3,557,472	3,501,003	3,166,368	1.6 %	10.6 %	3.92	3.96	3.94	(1.1)%	0.6 %
Nuclear	118,331	115,825	84,192	2.2 %	37.6 %	15,353,653	14,219,693	11,122,301	8.0 %	27.8 %	0.77	0.81	0.76	(5.4)%	7.6 %
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	481,776	321,268	323,614	50.0 %	(0.7)%	15,027,655	13,095,458	14,804,306	14.8 %	(11.5)%	3.21	2.45	2.19	30.7 %	12.2 %
Combustion Turbine	101,836	71,065	46,350	43.3 %	53.3 %	2,285,039	2,058,663	1,382,989	11.0 %	48.9 %	4.46	3.45	3.35	29.1 %	3.0 %
	\$ 841,342	\$ 612,440	\$ 578,794	37.4 %	5.8 %	36,223,819	32,874,817	30,475,964	10.2 %	7.9 %	2.32	1.86	1.90	24.7 %	(1.9)%

⁽¹⁾ For 2025, excludes test energy kilowatt-hours from Washington County and Talbot supplied to members. Any revenues and costs associated with test energy were capitalized. For 2024 and 2023, 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.

N/M - Not meaningful

Fuel

Total fuel expense increased in 2025 compared to 2024 as a result of an increase in average fuel cost and an overall increase in generation. The increase in average fuel cost was primarily due to higher average natural gas prices in 2025 compared to 2024. The increase in generation was primarily due to an increase in sales to our members as a result of the first full year of commercial operation for both Vogtle Units No. 3 and No. 4 and our members obtaining more of their energy requirements from us due to relative energy prices. 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 2025 and 2024, we included \$9.9 million and \$24.3 million of net gains and 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.

Production

Production costs can vary due to the number and extent of outages in a given year. Production costs increased 6.3% in 2025 compared to 2024 and increased 26.9% in 2024 compared to 2023. The increase in 2025 was due to higher production costs related to Plant Vogtle Unit No. 4 and the result of deferring BC Smith's effects on net margin during 2025 compared to 2024. 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 in 2024 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 \$86.0 million and \$72.6 million in credits recognized in 2025 and 2024, respectively, from the sale of nuclear production tax credits to Georgia Power.

Depreciation and amortization

Depreciation and amortization expense increased 11.0% in 2025 compared to 2024 primarily as a result of higher depreciation expense related to Vogtle Unit No. 4, which completed its first full year in 2025 after being placed in service on April 29, 2024. 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.

Other Income

The 34.0% decrease in other income in 2025 compared to 2024 was primarily due to a decrease in realized gains associated with our nuclear decommissioning funds in 2025 compared to 2024. 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.

Interest Charges

Interest expense increased in 2025 compared to 2024 primarily due to higher outstanding long-term debt balances in 2025 compared to 2024. 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 2025 compared to 2024. The commercial paper that we refinanced with these bond issues was used as interim financing for 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 2025 compared to 2024 primarily due to Vogtle Unit No. 4 being placed in service. Allowance for debt funds used during construction decreased in 2024 compared to 2023 due to Vogtle Units No. 3 and No. 4 being placed in service. As a result of these factors, net interest charges increased 9.4% in 2025. Net interest charges increased in 2025 compared to 2024 primarily due to higher outstanding long-term debt balances and the allowance for debt funds used during construction decreased due to Vogtle Unit No. 4 being placed in service. Net interest charges increased in 2024 compared to 2023 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 2025, we achieved a 1.10 margins for interest ratio which produced a net margin of \$55.4 million. This net margin increased our total patronage capital (our equity) and membership fees to \$1.4 billion at December 31, 2025.

Our equity to total capitalization ratio, as defined in our first mortgage indenture, was 9.9% at December 31, 2025 and 9.5% at December 31, 2024. We anticipate that our equity ratio will remain around its current level during the next several years due to the new generation construction; however, the absolute level of patronage capital will continue to increase.

We had a strong liquidity position at December 31, 2025 with \$1.5 billion of unrestricted available liquidity, including \$251.1 million of cash and cash equivalents. We issued commercial paper throughout the year to provide interim financing for Smarr combined cycle and Talbot combustion turbine unit No. 7 generation facilities construction, and for other general purposes. The average cost of funds on the \$459.5 million of commercial paper outstanding at December 31, 2025 was 4.05%.

Electric plant in service, net, increased \$516.8 million primarily due to construction work in progress at our Smarr combined cycle and Talbot combustion turbine unit No. 7 generation projects and our dual fuel construction projects at Washington County and Talbot being placed in service. The other capital additions include costs related to normal additions and replacements to existing generation facilities and purchases of nuclear fuel.

Nuclear decommissioning trust fund increased \$133.6 million primarily due to the increase in the fair market value of investments and the increase in investment income due to continued appreciation in the stock market in 2025. 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 8.47% in the last ten years and 6.68% 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 20.20% since inception in 2022.

Long-term investments increased primarily due to an increase in funds invested, including reinvestment of earnings, and an increase in fair market value of investments. Largely offsetting these increases were 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. See Notes 1e and 1q of Notes to Consolidated Financial Statements for a discussion of our member rate management programs and regulatory liabilities.

Receivables increased \$150.5 million at December 31, 2025 compared to December 31, 2024. The net increase was primarily due to a \$126.5 million increase in receivables from the U.S. Government relating to nuclear production tax credits for fiscal year 2024. See Note 1q and Note 8 of Notes to Consolidated Financial Statements for a discussion of nuclear production tax credits and regulatory liabilities.

Regulatory assets decreased by \$79.8 million at December 31, 2025 compared to December 31, 2024. The net decrease was primarily due to the decrease in the deferral associated with coal ash pond asset retirement obligations by \$39.7 million and by \$21.1 million in amortization of the deferral of accelerated depreciation associated with the early retirement of Plant Wansley, which occurred in August 2022.

Deferred charges and other assets increased \$42.4 million at December 31, 2025 compared to December 31, 2024. The net increase was primarily due to a \$53.6 million increase in a long-term receivable from the U.S. Government relating to nuclear production tax credits for fiscal year 2025. See Note 1q and Note 8 of Notes to Consolidated Financial Statements for a discussion of nuclear production tax credits and regulatory liabilities.

Long-term debt and long-term debt and finance leases due within one year decreased \$75.6 million at December 31, 2025 compared to December 31, 2024. The net decrease was primarily a result of \$348.2 million in debt service payments. Offsetting this decrease was the issuance of \$350.0 million of our Series 2025A green first mortgage bonds, reclassifying \$254.5 million of commercial paper that was refinanced through the issuance of the Series 2025A green first mortgage bonds and reclassified as long-term at December 31, 2024 to commercial paper debt in January 2025 and \$175.6 million in advances under Rural Utilities Service-guaranteed loans. The weighted average interest rate on the \$12.6 billion of long-term debt outstanding at December 31, 2025 was 4.07%.

Short-term borrowings, which primarily provided interim financing for Smarr combined cycle and Talbot Unit No. 7 construction costs, increased \$313.9 million at December 31, 2025 compared to December 31, 2024, primarily as a result of commercial paper issuances of \$326.9 million and the reclassification of \$254.5 million of commercial paper, that was classified as long-term debt at December 31, 2024, to short-term borrowings in January 2025. Offsetting these increases were repayments of \$267.5 million, primarily from the Series 2025A green first mortgage bonds proceeds.

Accounts payable increased \$110.0 million at December 31, 2025 compared to December 31, 2024. The increase was primarily due to a \$51.7 million increase in payables to Georgia Power, a \$22.5 million increase in trade accounts payable, and a \$21.0 million increase in payables for natural gas purchases and related transportation.

Regulatory liabilities increased by \$208.3 million at December 31, 2025 compared to December 31, 2024. The net increase was primarily due to a \$142.3 million increase in deferred nuclear asset retirement obligations that was primarily driven by an increase in unrealized gains associated with our nuclear decommissioning investments, an \$180.1 million increase in the regulatory liability for nuclear production tax credits, and a \$15.1 million increase in the liability for collections of future debt service payments. Offsetting these increases was an \$89.6 million decrease in the liability for our revenue deferral rate management plan, which is associated with the new Vogtle units, and an \$18.0 million decrease in the liability associated with unrealized gains on our natural gas contracts. See Note 1q and Note 8 of Notes to Consolidated Financial Statements for a discussion of nuclear production tax credits and regulatory liabilities.

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, 2025, we had \$3.9 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 Walton County acquisition and related costs. We plan to utilize these loans to provide long-term financing for our two new natural gas generation resources and other capital projects for existing 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 and by competition amongst cooperatives for available Rural Utilities Service funding. Because of these factors, we cannot predict the amount or cost of Rural Utilities Service loans that may be available to us in the future.

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 "BUSINESS – OGLETHORPE POWER CORPORATION – 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 for additional information regarding these loans.

Liquidity. At December 31, 2025, we had \$1.5 billion of unrestricted available liquidity to meet short-term cash needs and liquidity requirements, consisting of \$251.1 million of cash and cash equivalents and \$1.26 billion of unused and available committed credit arrangements.

Net cash provided by operating activities was \$502.1 million in 2025 and averaged \$375.2 million per year for the three-year period 2023 through 2025.

At December 31, 2025, we had \$1.725 billion of committed credit arrangements in place and \$1.26 billion available under four separate credit facilities. These are reflected in the table below:

Committed Credit Facilities				
(dollars in millions)				
	Authorized Amount	Available 12/31/2025	Expiration Date	
Unsecured Facilities:				
Syndicated Line among 11 banks led by CFC ⁽¹⁾	\$ 1,275	\$ 814	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, 2025.
- (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, 2025, \$2.5 million of this facility was used for letters of credit issued to provide performance assurance to third parties.

A portion of our unrestricted available liquidity is allocated to support \$40.5 million of weekly variable rate bonds that do not have external credit or liquidity support. The holders of these bonds may tender their bonds for purchase upon seven days' notice, and we are obligated to purchase any of these bonds which are tendered for purchase and not remarketed.

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 \$1.275 billion syndicated line of credit. At December 31, 2025, our outstanding commercial paper primarily was used to provide interim funding for:

- costs related to the new Smarr Combined Cycle and Talbot Unit No. 7 projects,
- costs related to the Walton County acquisition, and
- net costs, after off-system sales revenues, associated with recently acquired generation facilities (BC Smith, Baconton, Washington County, and Walton County) prior to recovery through member rates.

Rural Utilities Service financing is our preferred source of long-term financing for the Smarr Combined Cycle and Talbot Unit No. 7 projects. 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 net costs associated with recently acquired generation facilities that are incurred prior to recovery through member rates.

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, 2025. 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 for our 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, 2025, the highest required minimum level was \$900 million and our actual patronage capital balance was \$1.4 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, 2025, we had \$459.5 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, 2025, we had five members participating in the program and a balance of \$66.8 million remaining to be applied against future power bills.

Liquidity Covenants. At December 31, 2025, 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 2025 and expect to have sufficient liquidity to meet this covenant in 2026. For a discussion of the Rocky Mountain lease transaction, see Note 4 of Notes to Consolidated Financial Statements.

Financing Activities

First Mortgage Indenture. At December 31, 2025, we had \$12.6 billion of outstanding debt secured equally and ratably under our first mortgage indenture, an increase of \$177.4 million from December 31, 2024. 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, 2025, 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, 2025, we had \$947.6 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 that provided funding for over \$4.6 billion of the cost to construct our interest in Vogtle Units No. 3 and No. 4. We have fully advanced the \$4.6 billion available under these loans. As of December 31, 2025, we had repaid \$715.8 million under these loans and \$3.9 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.

Rural Utilities Service-Guaranteed Loans. A summary of our current Rural Utilities Service-Guaranteed Loans as of December 31, 2025 is provided in the table below:

Current Rural Utilities Service-Guaranteed Loans			
	Amount Approved	Amount Advanced December 31, 2025	Amount Remaining December 31, 2025
	(dollars in millions)		
General and Environmental Improvements	\$ 630.3	\$ 485.0	\$ 145.3
General and Environmental Improvements	755.2	338.5	416.7
General and Environmental Improvements	112.6	—	112.6
Walton Acquisition	80.1	—	80.1
Total	\$ 1,578.2	\$ 823.5	\$ 754.7

In 2025, we borrowed \$175.6 million under various Rural Utilities Service-guaranteed loans. This included a \$24.4 million advance on the \$630.3 million general and environmental improvements loan and a \$151.2 million advance on the \$755.2 million general and environmental improvements loan. In February 2026, we closed on a guaranteed loan of \$80.1 million for our acquisition of the Walton County Power Plant. When advanced, the debt will be secured ratably under our first mortgage indenture. In February 2026, we received a conditional commitment from the Rural Utilities Service for a guaranteed loan of \$112.6 million for general and environmental improvements. We expect to close and advance on that loan in 2027. We have also applied for an additional \$4.2 billion of Rural Utilities Service-guaranteed loans to provide for long-term financing for our Smarr Combined Cycle and Talbot Unit No. 7 projects as well as other capital projects. All loan

applications are subject to review and approval by the Rural Utilities Service and, if conditionally committed, remain subject to standard loan closing conditions. As of December 31, 2025, we had \$2.8 billion of debt outstanding under various Rural Utilities Service-guaranteed loans, an increase of \$23.3 million from December 31, 2024.

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 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 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 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.

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 2026 through 2028. 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)				
	2026	2027	2028	Total
Future Generation ⁽²⁾	\$ 834,909	\$ 1,211,397	\$ 829,892	\$ 2,876,198
Existing Generation ⁽³⁾	416,000	590,087	272,733	1,278,820
Environmental Compliance ⁽⁴⁾	31,614	28,559	11,392	71,565
Nuclear Fuel	126,052	113,580	151,121	390,753
General Plant	37,446	27,637	5,559	70,642
Total	\$ 1,446,021	\$ 1,971,260	\$ 1,270,697	\$ 4,687,978

- (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. No amounts have been included related to the potential Wansley combined cycle or Doyle combustion turbine projects.
- (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 "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, 2025, 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 \$112 million at a senior secured level of BB+/Ba1 or below, and

At senior unsecured or issuer rating levels:

- approximately \$62 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 \$52 million in collateral, based on their credit exposure to us as of December 31, 2025.

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 \$192 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 our 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

We have an executive risk management and compliance committee that provides general oversight over corporate compliance and all risk management activities, including, but not limited to, commodity trading, fuels management, insurance procurement, debt management, investment portfolio management, environmental compliance, and electric reliability compliance. This committee is comprised of our chief executive officer, chief operating officer, chief financial officer and the executive vice president, member 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, 2025, we had \$691.5 million of variable rate debt, \$272.2 million of intermediate-term fixed rate debt, and the remainder of our debt was long-term fixed rate debt. Our \$691.5 million of variable rate debt at December 31, 2025, included \$459.5 million of commercial paper outstanding (which typically has maturities of between 1 and 90 days) and \$232.0 million of pollution control bonds. These pollution control bonds include \$191.5 million of indexed variable rate bonds and \$40.5 million of variable rate demand bonds, all of which are subject to repricing weekly.

At December 31, 2025, the weighted average interest rate on our variable rate debt was 4.1%. If, during 2025, interest rates on this debt changed a hypothetical 100 basis points on the next respective repricing dates and remained at that level for the remainder of the year, annual interest expense would change by approximately \$6.7 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, 2025, we had 5.3% of our total debt, including commercial paper, classified as variable rate and 2.1% of our debt classified as intermediate-term fixed rate. The remaining 92.6% 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 other projects we may undertake, 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.

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, 2025 would result in a loss of value to the funds of approximately \$10.4 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 \$24.7 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 100% and 75% of our forecasted coal requirements for 2026 and 2027, 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 "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, 2025 was a net asset of approximately \$10.6 million, which represents the net amount we would have received if the swaps had been terminated as of that date. As of December 31, 2025, approximately 18% of our 2026 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 \$17.6 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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OGLETHORPE POWER CORPORATION
CONSOLIDATED STATEMENTS OF REVENUES AND EXPENSES

For the years ended December 31, 2025, 2024 and 2023

	(dollars in thousands)		
	2025	2024	2023
Operating revenues:			
Sales to members	\$ 2,442,690	\$ 2,145,522	\$ 1,681,566
Sales to non-members	98,502	36,325	58,619
Total operating revenues	2,541,192	2,181,847	1,740,185
Operating expenses:			
Fuel	\$ 841,342	\$ 612,440	\$ 578,794
Production	557,602	524,355	413,312
Depreciation and amortization	456,967	411,598	330,449
Purchased power	89,977	80,735	74,657
Accretion	58,759	69,223	65,907
Total operating expenses	\$ 2,004,647	\$ 1,698,351	\$ 1,463,119
Operating margin	\$ 536,545	\$ 483,496	\$ 277,066
Other income:			
Investment income	\$ 32,961	\$ 56,282	\$ 70,252
Amortization of deferred gains	1,789	1,789	1,789
Allowance for equity funds used during construction	3,033	1,756	750
Other	6,699	7,563	8,258
Total other income	\$ 44,482	\$ 67,390	\$ 81,049
Interest charges:			
Interest expense	\$ 538,569	\$ 521,525	\$ 515,862
Allowance for debt funds used during construction	(22,971)	(52,352)	(234,090)
Amortization of debt discount and expense	10,074	11,212	10,553
Net interest charges	\$ 525,672	\$ 480,385	\$ 292,325
Net margin	\$ 55,355	\$ 70,501	\$ 65,790

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2025 and 2024

	(dollars in thousands)	
	2025	2024
Assets		
Electric plant:		
In service	\$ 17,663,646	\$ 17,388,476
Right-of-use assets--finance leases	302,732	302,732
Less: Accumulated provision for depreciation	(5,933,906)	(5,701,627)
Electric plant in service, net	12,032,472	11,989,581
Nuclear fuel, at amortized cost	408,556	402,328
Construction work in progress	787,886	320,167
Total electric plant	13,228,914	12,712,076
Investments and funds:		
Nuclear decommissioning trust fund	855,223	721,624
Investment in associated companies	91,378	86,720
Long-term investments	653,265	645,166
Other	42,111	38,862
Total investments and funds	1,641,977	1,492,372
Current assets:		
Cash and cash equivalents	251,119	337,813
Restricted cash and short-term investments	500	500
Short-term investments	80,164	124,572
Receivables	397,059	246,581
Inventories, at weighted average cost	372,765	356,285
Prepayments and other current assets	45,472	44,218
Total current assets	1,147,079	1,109,969
Deferred charges and other assets:		
Regulatory assets	1,023,859	1,103,633
Prepayments to Georgia Power Company	22,419	16,334
Other	85,551	43,154
Total deferred charges and other assets	1,131,829	1,163,121
Total assets	\$ 17,149,799	\$ 16,477,538

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

OGLETHORPE POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31, 2025 and 2024

	(dollars in thousands)	
	2025	2024
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	\$ 1,383,773	\$ 1,328,418
Long-term debt	12,065,863	12,134,194
Obligations under finance leases	21,578	33,173
Obligation under Rocky Mountain transactions	34,099	31,910
Other	5,284	5,715
Total capitalization	13,510,597	13,533,410
Current liabilities:		
Long-term debt and finance leases due within one year	391,726	398,979
Short-term borrowings	459,513	145,604
Accounts payable	248,499	138,537
Accrued interest	91,146	81,425
Member power bill prepayments, current	28,453	31,258
Other current liabilities	215,193	140,611
Total current liabilities	1,434,530	936,414
Deferred credits and other liabilities:		
Asset retirement obligations	1,280,941	1,279,121
Member power bill prepayments, non-current	38,300	54,183
Regulatory liabilities	869,860	661,592
Other	15,571	12,818
Total deferred credits and other liabilities	2,204,672	2,007,714
Total equity and liabilities	\$ 17,149,799	\$ 16,477,538
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 CAPITALIZATION

December 31, 2025 and 2024

	(dollars in thousands)	
	2025	2024
Secured Long-term debt:		
First mortgage notes payable to the Federal Financing Bank at interest rates varying from 1.03% to 5.97% (average rate of 3.57% at December 31, 2025) due in quarterly installments through 2053	\$ 2,819,612	\$ 2,796,291
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, 2025) due in quarterly installments through 2044	3,917,257	4,050,644
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	375,000	437,500
• Series 2009B First Mortgage Bonds, 5.95%, due 2039	400,000	400,000
• 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	350,000
• Series 2025A First Mortgage Bonds, 5.90% due 2055	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 1, 2025, due 2038 through 2040	—	212,760
• Series 2013A Appling Weekly rate bonds, 2.50% due 2038	40,530	—
• Series 2013A Burke and Monroe Term rate bonds, 3.60% through February 1, 2030, due 2038 through 2040	172,230	—
• Series 2017A, B Burke Indexed put bonds-weekly reset, 4.27% 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, 3.60% through February 3, 2025, due 2041 through 2045	100,000	100,000
• Series 2017F Burke Indexed put bonds-weekly reset, 4.52% due 2040 through 2045	99,785	99,785
Total Secured Long-term debt	\$ 12,566,059	\$ 12,388,625
Unsecured debt:		
Commercial paper refinanced on a long-term basis	—	254,463
Total Long-term debt	\$ 12,566,059	\$ 12,643,088
Obligations under finance leases	33,173	43,586
Obligation under Rocky Mountain transactions	34,099	31,910
Other	5,284	5,715
Patronage capital and membership fees	1,383,773	1,328,418
Subtotal	\$ 14,022,388	\$ 14,052,717
Less: long-term debt and finance leases due within one year	(391,726)	(398,979)
Less: unamortized debt issuance costs	(96,978)	(97,623)
Less: unamortized bond discounts on long-term debt	(23,087)	(22,705)
Total capitalization	\$ 13,510,597	\$ 13,533,410

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, 2025, 2024 and 2023

	(dollars in thousands)		
	2025	2024	2023
Cash flows from operating activities:			
Net margin	\$ 55,355	\$ 70,501	\$ 65,790
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization, including nuclear fuel	\$ 629,202	\$ 569,349	\$ 441,926
Accretion cost	58,759	69,223	65,907
Amortization of deferred gains	(1,789)	(1,789)	(1,789)
Allowance for equity funds used during construction	(3,033)	(1,756)	(750)
Deferred outage costs	(43,866)	(46,065)	(32,390)
Gain on sale of investments	(38,068)	(90,356)	(6,954)
Regulatory deferral of costs associated with nuclear decommissioning	48,710	74,805	(21,449)
Other	(28,872)	(47,605)	(5,150)
Change in operating assets and liabilities:			
Receivables	(35,508)	(32,222)	12,011
Inventories	(16,480)	(34,717)	(38,562)
Prepayments and other current assets	(6,948)	(7,912)	(2,211)
Accounts payable	35,173	29,156	(104,164)
Accrued interest	9,721	(24,930)	903
Accrued taxes	5,446	9,678	1,087
Settlement of asset retirement obligations	(40,017)	(23,293)	(14,521)
Other current liabilities	42	36,778	(51,274)
Rate management program billing credits applied	(107,064)	(126,876)	(56,612)
Other	(18,689)	6,902	(57,281)
Total adjustments	\$ 446,719	\$ 358,370	\$ 128,727
Net cash provided by operating activities	\$ 502,074	\$ 428,871	\$ 194,517
Cash flows from investing activities:			
Property additions	\$ (890,366)	\$ (662,122)	\$ (474,952)
Plant acquisition	—	(75,240)	(16,743)
Litigation proceeds received for capitalized spent nuclear fuel storage costs	21,684	14,347	—
Activity in nuclear decommissioning trust fund – Purchases	(1,252,652)	(1,149,281)	(535,027)
Activity in nuclear decommissioning trust fund – Proceeds	1,221,699	1,129,631	520,986
Decrease in restricted investments	—	—	74,031
Activity in other long-term investments – Purchases	(286,160)	(264,277)	(262,712)
Activity in other long-term investments – Proceeds	359,382	354,894	199,200
Other	(6,311)	1,156	13,782
Net cash used in investing activities	\$ (832,724)	\$ (650,892)	\$ (481,435)
Cash flows from financing activities:			
Long-term debt proceeds	\$ 525,595	\$ 667,493	\$ 506,272
Long-term debt payments	(358,574)	(384,771)	(358,477)
Increase (decrease) in short-term borrowings, net	59,446	(207,818)	(47,765)
Other	17,489	(5,162)	51,699
Net cash provided by financing activities	243,956	69,742	151,729
Net decrease in cash, cash equivalents and restricted cash	\$ (86,694)	\$ (152,279)	\$ (135,189)
Cash, cash equivalents and restricted cash at beginning of period	338,313	490,592	625,781
Cash, cash equivalents and restricted cash at end of period	\$ 251,619	\$ 338,313	\$ 490,592
Supplemental cash flow information:			
Cash paid for –			
Interest (net of amounts capitalized)	\$ 503,688	\$ 492,055	\$ 278,952
Supplemental disclosure of non-cash investing and financing activities:			
Change in asset retirement obligations	\$ (16,605)	\$ (225,604)	\$ 63,803
Accrued property additions at end of period	\$ 194,785	\$ 49,683	\$ 39,854

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, 2025, 2024 and 2023

	(dollars in thousands)
Balance at December 31, 2022	\$ 1,192,127
Components of comprehensive margin in 2023:	
Net margin	65,790
Balance at December 31, 2023	\$ 1,257,917
Components of comprehensive margin in 2024:	
Net margin	70,501
Balance at December 31, 2024	\$ 1,328,418
Components of comprehensive margin in 2025:	
Net margin	55,355
Balance at December 31, 2025	\$ 1,383,773

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2025, 2024 and 2023

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 8,589 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. Certain prior year amounts have been reclassified to conform with current year presentation.

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, 2025 and 2024 and the reported amounts of revenues and expenses for each of the three years in the period ended December 31, 2025. 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, identifying which of our generation plants have a legal obligation, making projections for when our generation plants will be retired, estimating the decommissioning and closure costs, and evaluating how costs will escalate with inflation. Actual results could differ from our 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 2025, we achieved a margins for interest ratio of 1.10. For 2024 and 2023, 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, 2025 and 2024, 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 2025, our board approved, and we achieved, a targeted margins for interest ratio of 1.10. For 2024 and 2023, our board approved, and we achieved, a targeted margins for interest ratio of 1.14. For 2026, 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, 2025 and December 31, 2024, we recognized refund liabilities totaling \$70,632,000 and \$55,914,000, 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)		
	2025	2024	2023
Capacity revenues	\$ 1,603,888	\$ 1,501,903	\$ 1,082,368
Energy revenues	838,802	643,619	599,198
Total	\$ 2,442,690	\$ 2,145,522	\$ 1,681,566

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 in our 2024 Form 10-K.

The following table reflects members whose revenues accounted for 10% or more of our total operating revenues in 2025, 2024 or 2023:

	2025	2024	2023
Jackson EMC	18.0 %	18.0 %	15.1 %
Cobb EMC	8.1 %	9.0 %	11.4 %

Energy revenues from non-members were primarily from the sale of the BC Smith deferring members' output into the wholesale market. In 2025, BC Smith did not undergo a major maintenance outage as it did in 2024, therefore, we generated and sold more megawatt-hours of off-system energy from BC Smith compared with 2024. 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 2024 and 2023, 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)		
	2025	2024	2023
Energy revenues	\$ 98,502	\$ 34,753	\$ 44,995
Capacity revenues	—	1,572	13,624
Total	\$ 98,502	\$ 36,325	\$ 58,619

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.

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, billing credits to participating members during 2025, 2024 and 2023 were \$96,927,000, \$121,638,000 and \$52,378,000 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, 2025, \$107,784,000 was 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, 2025, 2024 and 2023 were \$237,834,000, \$177,790,000 and \$170,901,000, 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 nuclear production tax credits and transactions with non-members for the sale of the BC Smith deferring members' output, affiliated companies and investment income. Our receivables from non-members at December 31, 2025, included a receivable of \$126,517,000 from the U.S. Government relating to nuclear production tax credits ("45U NPTCs"), pursuant to Internal Revenue Code 45U for fiscal year 2024. We have applied regulatory accounting to these tax credits and are deferring the benefit until the three-year Internal Revenue Service ("IRS") statute of limitations has passed and/or completion of an IRS audit for 2024 45U NPTCs. For information regarding regulatory accounting, see Note 1q. Our receivables from non-members at December 31, 2025, 2024 and 2023 were \$159,225,000 and \$68,791,000, and \$30,883,000, respectively.

As of December 31, 2025, we have recognized a long-term receivable of \$53,566,000 from the U.S. Government relating to 45U NPTCS for fiscal year 2025. We also have applied regulatory accounting to these tax credits and are deferring the benefit until the three-year IRS statute of limitations has passed and/or completion of an IRS audit for 2025 45U NPTCs. For information regarding regulatory accounting, see Note 1q.

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 2025, 2024 and 2023, 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 2025, 2024 and 2023 amounted to \$118,331,000, \$81,425,000, and \$84,192,000, 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 Units No. 1 and No. 2. The Department of Energy failed to begin disposing of spent fuel in January 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants, is pursuing legal remedies against the Department of Energy for breach of contract.

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. As of December 31, 2025, no amounts are outstanding.

In September 2025, Georgia Power filed their fifth round of lawsuits against the U.S. government in the Court of Federal Claims, seeking damages for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units No. 1 and No. 2 for the period from January 1, 2020 through December 31, 2024. 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.

No amounts have been recognized in our consolidated financial statements as of December 31, 2025 for any potential recoveries from the pending lawsuits. The final outcome of this matter cannot be determined at this time.

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 future costs 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 nuclear decommissioning costs and coal ash pond closure costs. 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 legally obligated retirement costs 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 nuclear decommissioning costs and coal ash pond closure costs are based on the most recent studies performed in 2024 and 2025, respectively.

The following table reflects the details of the asset retirement obligations included in the consolidated balance sheets for the years 2025 and 2024.

	(dollars in thousands)			
	Nuclear	Coal Ash Pond	Other	Total
Balance at December 31, 2024	\$ 812,239	\$ 403,170	\$ 63,712	\$ 1,279,121
Liabilities settled	—	(39,053)	(964)	(40,017)
Accretion	39,523	16,196	3,040	58,759
Deferred accretion	—	(317)	—	(317)
Change in cash flow estimates	—	(23,475)	6,870	(16,605)
Balance at December 31, 2025	\$ 851,762	\$ 356,521	\$ 72,658	\$ 1,280,941

	(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

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 2024, we performed a revised assessment of our nuclear decommissioning asset retirement obligations for Plants Hatch and Vogtle. The revised studies incorporated updated assumptions regarding expected decommissioning dates. 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. In evaluating the significant assumptions used in the studies, management considered factors including, but not limited to, examination of the nuclear units' remaining licensed and economic lives, re-licensing expectations, regulatory requirements and industry trends. These significant assumptions are evaluated at least annually and updated as necessary based on current information.

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, we recognized a new nuclear asset retirement obligation for Plant Vogtle Unit No. 3 totaling \$62,841,000 in 2023 and for Unit No. 4 totaling \$65,100,000 in 2024. Our portion of the estimated costs of decommissioning co-owned nuclear facilities for which we have recorded asset retirement

obligations as of December 31, 2025 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	\$ 348,000	\$ 358,000	\$ 333,000	\$ 347,000

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	\$ 247,000	\$ 261,000

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 2025 and 2024, assessments of the coal ash pond asset retirement obligation resulted in decreases in cash flow estimates of \$23,475,000 and \$56,171,000, respectively. These adjustments to the asset retirement obligations had a corresponding offset to our coal ash related regulatory asset. The 2025 and 2024 decreases were 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. Asset retirement obligations may be adjusted in future periods as a result of changes in estimates and assumptions.

We have internally segregated the funds collected for coal ash pond and other CCR closure costs, including earnings thereon. As of December 31, 2025 and December 31, 2024, the fund balances were \$219,634,000 and \$201,535,000, 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 closure transactions such that collections and investment income (interest, dividends and realized gains and losses) are compared to the associated closure expenses with the difference deferred to or amortized from the regulatory asset. This difference recorded to the associated expenses in our consolidated statements of revenues and expenses. Unrealized gains and losses of the associated coal ash 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 2025 and 2024, we contributed \$11,000,000 and \$8,632,000, 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 \$10,833,000 and \$8,333,000 into the internal funds in 2025 and 2024, respectively.

The following table outlines the fair value of our nuclear decommissioning funds as of December 31, 2025 and December 31, 2024. The funds were invested in a diversified mix of approximately 62% equity, and 38% fixed income securities in 2025 and 51% equity, 34% fixed income securities and 15% temporarily in cash pending reallocation between equity funds in 2024.

	2025				
	(dollars in thousands)				
<i>External Trust Funds:</i>	Cost 12/31/2024	Purchases	Net Proceeds ⁽¹⁾	Unrealized Gain(Loss)	Fair Value 12/31/2025
Equity	\$ 343,529	\$ 22,516	\$ 27,482	\$ 248,075	\$ 641,602
Debt	202,356	1,198,611	(1,184,252)	(618)	216,097
Other	(1,677)	38,968	(39,767)	—	(2,476)
	\$ 544,208	\$ 1,260,095	\$ (1,196,537)	\$ 247,457	\$ 855,223

(1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of \$63,558,000.

	2025				
	(dollars in thousands)				
<i>Internal Funds:</i>	Cost 12/31/2024	Purchases	Net Proceeds ⁽¹⁾	Unrealized Gain(Loss)	Fair Value 12/31/2025
Equity	\$ 89,635	\$ —	\$ 5,314	\$ 59,745	\$ 154,694
Debt	72,879	175,854	(159,785)	1,591	90,539
	\$ 162,514	\$ 175,854	\$ (154,471)	\$ 61,336	\$ 245,233

- (1) Also included in net proceeds are net realized gains or losses, interest income, dividends, contributions and fees of \$21,383,000.

External Trust Funds:	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)	
	\$ 444,090	\$ 1,149,283	\$ (1,049,165)	\$ 177,416	\$ 721,624	

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

Internal Funds:	2024					
	(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	
	\$ 135,698	\$ 139,657	\$ (112,841)	\$ 38,286	\$ 200,800	

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

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 rates from depreciation rate studies completed in various years. Site specific depreciation studies are performed at a minimum of every five years. Annual weighted average depreciation rates in effect in 2025, 2024, and 2023 were as follows:

	2025	2024	2023
Steam production	3.04 %	3.04 %	3.05 %
Nuclear production	1.85 %	1.88 %	1.87 %
Hydro production	2.00 %	2.00 %	2.00 %
Other production	2.65 %	2.71 %	2.73 %
Transmission	2.75 %	2.75 %	2.75 %
General	2.00-33.33%	2.00-33.33%	2.00-33.33%

Depreciation expense for the years 2025, 2024 and 2023 was \$424,243,000, \$404,178,000, and \$321,047,000, respectively. In 2025, depreciation expense increased by \$20,065,000 compared to 2024 primarily due to a full year of operating Plant Vogtle Unit No. 4 and Walton County, which was acquired in 2024. 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 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 \$21,074,000, \$20,603,000 and \$25,900,000 of deferred depreciation expense in 2025, 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 2025, 2024 and 2023, the allowance for funds used during construction rates were 4.32%, 4.29% and 4.18%, 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, 2025	December 31, 2024
	(dollars in thousands)	
Cash and cash equivalents	\$ 251,119	\$ 337,813
Restricted cash included in restricted cash and short-term investments	500	500
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	\$ 251,619	\$ 338,313

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 inventory primarily includes 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, 2025 and December 31, 2024, fossil fuels inventories were \$68,169,000 and \$83,705,000, respectively. Inventories for spare parts at 2025 and 2024 were \$304,596,000 and \$272,580,000, respectively.

o. Deferred charges and other assets

Deferred charges and other assets represent regulatory assets, long-term prepayments to Georgia Power and other deferred charges. Other deferred charges primarily represent a long-term receivable from the U.S. Government relating to nuclear production tax credits for fiscal year 2025 and the fair value of our natural gas contracts that will settle after the next

twelve months and other long-term prepayments. For a discussion regarding regulatory assets and liabilities and nuclear production tax credits, see Note 1q and Note 8, respectively.

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 2027.

Deferred credits and other liabilities also consist 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)	
	2025	2024
<i>Regulatory Assets:</i>		
Premium and loss on reacquired debt(a)	\$ 20,173	\$ 21,587
Amortization on financing leases(b)	19,556	24,699
Outage costs(c)	46,781	45,749
Asset retirement obligations – Ashpond and other(l)	228,400	268,074
Depreciation expense - Plant Vogtle(d)	31,279	32,702
Depreciation expense - Plant Wansley(e)	316,106	337,181
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs(f)	53,619	54,545
Interest rate options cost(g)	123,650	130,456
Deferral of effects on net margin – TA Smith Energy Facility(h)	118,896	124,840
Deferral of effects on net margin – BC Smith Energy Facility(p)	13,868	27,841
Inventory adjustments - TA Smith Energy Facility(q)	13,701	14,723
Accumulated retirement costs for other obligations(i)	5,479	—
Other regulatory assets(o)	32,351	21,236
<i>Total Regulatory Assets</i>	\$ 1,023,859	\$ 1,103,633
<i>Regulatory Liabilities:</i>		
Accumulated retirement costs for other obligations(i)	—	\$ 29,975
Deferral of effects on net margin – Hawk Road Energy Facility(h)	14,788	15,404
Major maintenance reserve(j)	109,028	99,987
Deferred debt service adder(k)	201,836	186,757
Asset retirement obligations – Nuclear(l)	245,133	102,858
Revenue deferral plan(m)	107,784	197,373
Natural gas hedges(n)	10,642	28,624
Deferral of direct pay nuclear production tax credits(r)	180,082	—
Other regulatory liabilities(o)	567	614
<i>Total Regulatory Liabilities</i>	\$ 869,860	\$ 661,592
<i>Net regulatory assets</i>	\$ 153,999	\$ 442,041

(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 30 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 2023 after Vogtle Unit No. 3 was placed in service.
- (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 deferral or 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 future decommissioning or closure costs for financial statement purposes versus ratemaking purposes, as well as the deferral of unrealized gains and losses of funds set aside for decommissioning or closure.
- (m) Deferred revenues under a rate management program that allowed for additional collections from 2018 through 2022 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 28 years and the amortization periods of other regulatory liabilities range up to 1 year.
- (p) Effects on net margin for the BC Smith Energy Facility that are expected to be deferred until November 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) Represents deferral of direct pay 45U NPTCs recognized for fiscal years 2024 and 2025. Both fiscal years were recognized at December 31, 2025. These 45U NPTCs, remain subject to an IRS audit until the three-year IRS statute of limitations has passed and/or completion of an IRS audit for that year's 45U NPTCs (an "Examination Period"). We will amortize these 45U NPTCs as credits to the Production expense line item within our consolidated statements of revenues and expenses after the lapse of the applicable Examination Period for that year's 45U NPTCs, with an estimated amortization period end date of December 31, 2028 and December 31, 2029, for fiscal year 2024 and fiscal year 2025 tax credits, respectively. We expect to defer and amortize such 45U NPTCs claimed for fiscal years subsequent to 2024 and 2025 in a similar manner on a rolling three-year basis.

r. Related parties

We and our 38 members are members of Georgia Transmission Corporation. 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 2025, 2024, and 2023, we incurred expenses from Georgia Transmission of \$46,353,000, \$43,965,000, and \$41,426,000, 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 2025, 2024, and 2023, we incurred expenses from Georgia System Operations of \$37,271,000, \$32,932,000, and \$30,109,000, respectively.

s. Other income

Other income includes net revenue from Georgia Transmission and Georgia System Operations Corporation 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 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 have fully completed our evaluation of this new standard. The adoption of this standard on December 31, 2025 did not have a material impact on our consolidated financial statements. For the related income tax disclosures, see Note 5.

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.

In September 2025, the FASB issued "Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software", which modernizes the accounting for internal-use software under Accounting Standards Codification (ASC) 350-40 by aligning it with current development practices, especially agile and iterative methods. It clarifies when to begin capitalizing costs, improves operability across different development approaches, and enhances disclosure requirements. The new standard is effective for us for interim and annual periods beginning after December 15, 2027, with early adoption permitted. 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, 2025	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	\$ 254,191	\$ 254,191	\$ —	\$ —
Corporate bonds and debt	\$ 108,799	—	107,808	991
US Treasury securities	\$ 85,520	85,520	—	—
Mortgage backed securities	\$ 65,814	—	65,814	—
Domestic mutual funds	\$ 109,307	109,307	—	—
Municipal bonds	\$ 6,627	—	6,627	—
Federal agency securities	\$ 9,082	—	9,082	—
Non-US Gov't bonds & private placements	\$ 14,234	—	14,234	—
International mutual funds	\$ 180,112	—	180,112	—
Other	\$ 21,537	21,537	—	—
Long-term investments:				
Corporate bonds and debt	\$ 27,967	—	27,967	—
US Treasury securities	\$ 36,716	36,716	—	—
Mortgage backed securities	\$ 28,996	—	28,996	—
Domestic mutual funds	\$ 430,593	430,593	—	—
Treasury STRIPS	\$ 76,392	—	76,392	—
Non-US Gov't bonds & private placements	\$ 3,294	—	3,294	—
International mutual funds	\$ 48,935	—	48,935	—
Other	\$ 372	372	—	—
Short-term investments: Treasury STRIPS	\$ 80,164	—	80,164	—
Natural gas swaps	\$ 10,642	—	10,642	—

	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	—

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 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, 2025 and 2024 were as follows:

	2025		2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
(in thousands)				
Long-term debt	\$ 12,566,059	\$ 11,008,470	\$ 12,643,088	\$ 10,666,727

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, 2025 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, 2025 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, 2025 and 2024, the estimated fair values of our natural gas contracts were net assets of \$10,642,000 and \$28,624,000, respectively.

As of December 31, 2025 and 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.

The following table reflects the volume activity of our natural gas derivatives as of December 31, 2025 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2026	25.6
2027	21.6
2028	11.6
2029	11.8
2030	12.8
Total	83.4

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, 2025 and 2024. 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					
		2025			2024		
		Assets	Liabilities	Net Carrying Value Presented on the Balance Sheet	Assets	Liabilities	Net Carrying Value Presented on the Balance Sheet
(dollars in thousands)							
Assets							
Natural gas swaps	Other current assets	\$ 14,775	\$ (2,505)	\$ 12,270	\$ 19,527	\$ (1,563)	\$ 17,964
Natural gas swaps	Other deferred charges	3,084	(1,251)	1,833	17,566	(5,279)	12,287
Liabilities							
Natural gas swaps	Other current liabilities	\$ 145	\$ (435)	\$ (290)	\$ 290	\$ (1,917)	\$ (1,627)
Natural gas swaps	Other deferred credits	1,020	(4,191)	(3,171)	—	—	—
Total		\$ 19,024	\$ (8,382)	\$ 10,642	\$ 37,383	\$ (8,759)	\$ 28,624

The following table presents the realized gains and (losses) on derivative instruments recognized in margin for the years ended December 31, 2025, 2024 and 2023.

Consolidated Statement of Revenues and Expenses Location		2025	2024	2023
(dollars in thousands)				
Natural gas swaps gains	Fuel	\$ 15,638	\$ 1,213	\$ 2,001
Natural gas swaps losses	Fuel	(5,747)	(25,510)	(22,924)
Total		\$ 9,891	\$ (24,297)	\$ (20,923)

The following table presents the unrealized (gains) and losses on derivative instruments deferred on the consolidated balance sheets at December 31, 2025 and 2024.

		Consolidated Balance Sheet Location			
				2025	2024
				(dollars in thousands)	
Natural gas swaps	Regulatory liability	\$		10,642	\$ 28,624
Total		\$		10,642	\$ 28,624

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, 2025 and 2024.

(dollars in thousands)					
Gross Unrealized					
2025	Cost	Gains	Losses	Fair Value	
Equity	\$ 407,059	\$ 313,033	\$ (4,440)	\$ 715,652	
Debt	850,056	10,509	(9,398)	851,167	
Other	22,506	205	(878)	21,833	
Total	\$ 1,279,621	\$ 323,747	\$ (14,716)	\$ 1,588,652	

(dollars in thousands)					
Gross Unrealized					
2024	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	

The cost basis of our debt securities that were in unrealized loss positions at December 31, 2025 was \$324,301,000. At December 31, 2025, \$1,178,000 of the \$9,398,000 of unrealized losses relates to securities that have been in unrealized loss positions for less than twelve months and \$8,220,000 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 following our purchase of these securities.

The contractual maturities of debt securities, which are included in the estimated fair value table above, at December 31, 2025 and 2024 are as follows:

(dollars in thousands)					
		2025		2024	
	Cost	Fair Value	Cost	Fair Value	
Due within one year	\$ 446,048	\$ 450,544	\$ 489,744	\$ 488,062	
Due after one year through five years	134,402	135,895	188,519	185,714	
Due after five years through ten years	94,416	95,596	63,526	62,123	
Due after ten years	175,190	169,132	122,785	114,549	
Total	\$ 850,056	\$ 851,167	\$ 864,574	\$ 850,448	

The following table summarizes the realized gains and losses and proceeds from sales of securities for the years ended December 31, 2025, 2024 and 2023:

	(dollars in thousands)		
	2025	2024	2023
Gross realized gains	\$ 39,726	\$ 101,549	\$ 15,518
Gross realized losses	(1,658)	(11,193)	(8,564)
Proceeds from sales	1,581,081	1,484,525	720,186

Investment in associated companies

Investments in associated companies were as follows at December 31, 2025 and 2024:

	(dollars in thousands)	
	2025	2024
National Rural Utilities Cooperative Finance Corporation (CFC)	\$ 23,899	\$ 23,983
CT Parts, LLC	6,795	6,561
Georgia Transmission Corporation	49,150	44,936
Georgia System Operations Corporation	7,500	7,250
Other	4,034	3,990
Total	\$ 91,378	\$ 86,720

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 represent 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 \$4,634,000.

In connection with the end of the lease term, we have exercised our 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., is expected to fund approximately \$74,000,000 and \$37,928,000 of this amount, respectively, and these amounts are expected to be paid to the owner trust over five installments in 2027.

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 allocated to members when calculating 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. As a result, we generally do not incur current period income tax expense and do not record a net deferred income tax asset or 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:

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Statutory federal income tax rate	\$ 11,625	21.0 %	\$ 14,805	21.0 %	\$ 13,816	21.0 %
Patronage exclusion	(11,625)	(21.0)%	(14,805)	(21.0)%	(13,816)	(21.0)%
Effective income tax rate	\$ —	0.0 %	\$ —	0.0 %	\$ —	0.0 %

Substantially all operations are conducted in the United States; therefore, income before income taxes is entirely attributable to domestic operations for all periods presented. Income taxes paid, net of refunds, were zero for the years ended December 31, 2025, 2024 and 2023.

The components of our net deferred tax assets and liabilities as of December 31, 2025 and 2024 were as follows:

(dollars in thousands)			
	2025		2024
Deferred tax assets			
Net operating losses	\$ 214,816	\$	157,190
Obligation related to asset retirements	319,494		319,040
Advance payments	121,095		142,949
Other regulatory liabilities	63,528		36,973
Other assets	14,110		13,026
Deferred tax assets	733,043		669,178
Less: Valuation allowance	—		—
Net deferred tax assets	\$ 733,043	\$	669,178
Deferred tax liabilities			
Fixed assets and intangibles	\$ (239,649)	\$	(175,777)
Right-of-use assets-finance leases	(75,508)		(75,508)
Other regulatory asset	(361,775)		(338,048)
Other liabilities	(18,244)		(19,024)
Deferred tax liabilities	(695,176)		(608,357)
Net deferred tax assets (liabilities)	\$ 37,867	\$	60,821
Less: Impact of patronage dividend allocation	(37,867)		(60,821)
Net deferred taxes	\$ —	\$	—

As of December 31, 2025, we have federal and state net operating loss carryforwards of \$861,260,000. Federal net operating loss carryforwards may be carried forward indefinitely. State net operating loss carryforwards may be carried forward for periods ranging from fifteen years to indefinitely, depending on the applicable state jurisdiction. Due to the tax

basis method for allocating patronage dividends, these losses would be utilized to offset any future federal taxable income prior to member allocation per the bylaws. Accordingly, 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 2022 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 2022 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 2025 and 2024 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 October 31, 2030. 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	2025	2024
	(dollars in thousands)	
Right-of-use assets - Finance leases		
Right-of-use assets	\$ 302,732	\$ 302,732
Less: Accumulated provision for depreciation	(288,688)	(283,417)
Total finance lease assets	\$ 14,044	\$ 19,315
Lease liabilities - Finance leases		
Obligations under finance leases	\$ 21,578	\$ 33,173
Long-term debt and finance leases due within one year	11,595	10,413
Total finance lease liabilities	\$ 33,173	\$ 43,586

Classification	2025	2024
	(dollars in thousands)	
Right-of-use assets - Operating leases		
Electric plant in service, net	\$ 7,357	\$ 7,723
Total operating lease assets	\$ 7,357	\$ 7,723
Lease liabilities - Operating leases		
Capitalization - Other	\$ 5,284	\$ 5,715
Other current liabilities	2,073	1,954
Total operating lease liabilities	\$ 7,357	\$ 7,669

	2025	2024
	(dollars in thousands)	
Lease Cost	Classification	
Finance lease cost:		
Amortization of leased assets	Depreciation and amortization	\$ 10,413 \$ 9,351
Interest on lease liabilities	Interest expense	\$ 4,536 \$ 5,598
Operating lease cost	Inventory ⁽¹⁾ & production expense	\$ 2,429 \$ 2,287
Total lease cost		\$ 17,378 \$ 17,236

⁽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, 2025	December 31, 2024
Lease Term and Discount Rate		
Weighted-average remaining lease term (in years):		
Finance leases	3.55	4.37
Operating leases	4.36	5.01
Weighted-average discount rate:		
Finance leases	11.05 %	11.05 %
Operating leases	6.14 %	6.34 %

	2025	2024
	(dollars in thousands)	
Other Information:		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance leases	\$ 4,536	\$ 5,598
Operating cash flows from operating leases	\$ 2,429	\$ 2,381
Financing cash flows from finance leases	\$ 10,413	\$ 9,351
Right-of-use assets obtained in exchange for new operating lease liabilities	\$ 1,670	\$ 2,951

Maturity analysis of our finance and operating lease liabilities as of December 31, 2025 is as follows:

	(dollars in thousands)		
Year Ending December 31,	Finance Leases	Operating Leases	Total
2026	\$ 14,949	\$ 2,467	\$ 17,416
2027	14,949	2,190	17,139
2028	3,052	2,080	5,132
2029	3,052	643	3,695
2030	3,052	389	3,441
Thereafter	1,528	651	2,179
Total lease payments	\$ 40,582	\$ 8,420	\$ 49,002
Less: imputed interest	(7,409)	(1,063)	(8,472)
Present value of lease liabilities	\$ 33,173	\$ 7,357	\$ 40,530

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 2025 and 2024 was as follows:

	2025	2024
	(dollars in thousands)	
Lease income	\$5,221	\$5,561

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 2030 are as follows:

	(dollars in thousands)					
	2026	2027	2028	2029	2030	
FFB	\$ 277,101	\$ 253,087	\$ 297,901	\$ 346,710	\$ 315,442	
FMBs	62,500	62,500	62,500	62,500	62,500	
PCRBs ⁽¹⁾	40,530	—	91,645	99,785	—	
	\$ 380,131	\$ 315,587	\$ 452,046	\$ 508,995	\$ 377,942	
Finance Leases	11,595	12,912	2,153	2,397	2,669	
Total	\$ 391,726	\$ 328,499	\$ 454,199	\$ 511,392	\$ 380,611	

- ⁽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. Amounts reflected in 2028 represent the Series 2017A and 2017B Burke indexed put bonds, which are subject to a mandatory tender in September 2027. If not successfully remarketed at that time, the bonds would enter a failed remarketing period and be subject to mandatory redemption in September 2028. Amounts reflected in 2029 represent the Series 2017F Burke indexed put bonds, which are subject to a mandatory tender on February 1, 2028. If not successfully remarketed at that time, the bonds would enter a failed remarketing period and be subject to mandatory redemption in February, 2029. There are no scheduled debt maturities for the PCRBs through 2030.

The weighted average interest rate on our long-term debt at December 31, 2025 and 2024 was 4.07% and 3.95%, respectively. The weighted average interest rate on our short-term borrowings at December 31, 2025 and 2024 was 4.05% and 4.80%, 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, 2025 and December 31, 2024 are as follows:

	2025		2024	
	Principal	Unamortized Debt Issuance Costs and Debt Discounts	Principal	Unamortized Debt Issuance Costs and Debt Discounts
	(dollars in thousands)			
FFB	\$ 6,736,869	\$ 46,268	\$ 6,846,935	\$ 48,947
FMBs	5,125,000	65,617	4,837,500	63,373
PCRBs	704,190	8,180	704,190	8,008
	\$ 12,566,059	\$ 120,065	\$ 12,388,625	\$ 120,328

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:*

In connection with the development and construction of Vogtle Units No. 3 and No. 4, we and the Department of Energy and the Federal Financing Bank entered into a series of agreements pursuant to which we borrowed \$4,633,028,000. As of December 31, 2025, we have repaid \$715,771,000 of principal on the notes related to these borrowings and the aggregate

Department of Energy-guaranteed borrowings outstanding, including capitalized interest, totaled \$3,917,257,000. The final maturity date is February 20, 2044.

b) *Rural Utilities Service Guaranteed Loans:*

During 2025, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling \$175,595,000, consisting of \$24,368,000 and \$151,227,000 for two loans of long-term financing of general and environmental improvements at existing plants.

In January 2026, we received an additional \$43,332,000 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:*

As of December 31, 2025, 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, 2025, 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, 2025, we had (i) \$2,504,000 under these lines of credit in the form of issued letters of credit and (ii) \$461,149,000 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 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 contain a provision that could accelerate their payment to the current year under certain circumstances, these bonds are included within 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, 2025 and 2024 is as follows:

2025

2024

(dollars in thousands)

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Plant	Investment	Accumulated Depreciation	Investment	Accumulated Depreciation
In-service ⁽¹⁾				
Owned property				
Vogtle Units No. 1 & No. 2 (Nuclear – 30% ownership)	\$ 2,908,491	\$ (1,965,417)	\$ 2,941,737	\$ (1,958,308)
Vogtle Units No. 3 and No. 4 (Nuclear – 30% ownership) ⁽²⁾	8,003,060	(286,647)	7,966,038	(153,949)
Hatch Units No. 1 & No. 2 (Nuclear – 30% ownership)	915,953	(568,987)	912,629	(558,916)
Wansley Common (Fossil – 30% ownership)	30,894	(28,641)	26,603	(23,344)
Scherer Unit No. 1 (Fossil – 60% ownership)	1,353,887	(703,748)	1,369,982	(690,307)
Doyle (Combustion Turbine - 100% ownership)	157,751	(133,076)	151,697	(130,479)
Rocky Mountain Units No. 1, No. 2 & No. 3 (Hydro – 74.61% ownership)	624,279	(331,658)	619,581	(319,528)
Hartwell (Combustion Turbine - 100% ownership)	244,632	(135,252)	239,570	(134,649)
Hawk Road (Combustion Turbine - 100% ownership)	281,032	(91,954)	277,099	(84,004)
Talbot Units No. 1 - No. 6 (Combustion Turbine - 100% ownership)	414,987	(175,240)	310,826	(172,890)
Chattahoochee (Combined cycle - 100% ownership)	362,721	(174,919)	354,570	(172,094)
BC Smith (Combined cycle - 100% ownership)	465,758	(123,642)	413,829	(119,228)
TA Smith (Combined cycle - 100% ownership)	716,742	(252,913)	702,383	(243,554)
Washington County Unit No. 2 and Unit No. 3 (Combustion Turbine – 100% ownership)	215,967	(97,664)	171,937	(94,418)
Baconton Unit 500 (Combustion Turbine – 100% ownership)	33,630	(17,577)	33,910	(16,900)
Walton County (Combustion Turbine – 100% ownership)	163,010	(32,715)	121,718	(43,697)
Transmission plant	176,187	(81,654)	173,183	(77,295)
Other	104,625	(63,257)	103,785	(64,004)
Property under finance lease:				
Scherer Unit No. 2 (Fossil – 60% leasehold)	792,772	(668,945)	800,131	(644,063)
Total in-service	\$ 17,966,378	\$ (5,933,906)	\$ 17,691,208	\$ (5,701,627)
Construction work in progress				
Hatch Units No. 1 & No. 2 (Nuclear – 30% ownership)	\$ 69,217		\$ 29,563	
Scherer Units No. 1 & No. 2 (Fossil – 60% ownership & 60% leasehold)	81,106		42,774	
Vogtle Units No. 1 & No. 2 (Nuclear – 30% ownership)	79,323		22,842	
Vogtle Units No. 3 and No. 4 (Nuclear – 30% ownership) ^(2,3)	31,723		10,623	
Wansley Common (Fossil – 30% ownership)	5,437		152	
Smarr CC (Combined cycle - 100% ownership)	343,532		—	
Talbot Unit No. 7 (Combustion Turbine - 100% ownership)	61,497		—	
Environmental and other generation improvements	116,051		214,213	
Total construction work in progress	\$ 787,886		\$ 320,167	

(1) Amounts include \$330,730,000 of plant acquisition adjustments at December 31, 2025 and 2024.

(2) Plant Vogtle Units No. 3 and No. 4 were placed in service on July 31, 2023 and April 29, 2024, respectively.

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 Power), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. 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 727 megawatts of nameplate capacity, as constructed, and a summer planning reserve capacity of 670 megawatts.

Vogtle Unit No. 3 and No. 4 site demobilization efforts have been completed, and remaining contractor obligations have been substantially satisfied. As of December 31, 2025, 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 \$427 million we received from Georgia Power pursuant to the cost-sharing provisions in a settlement agreement with Georgia Power.

45J Nuclear Production Tax Credits ("45J NPTCs")

In 2025 and 2024, since Plant Vogtle Units No. 3 and No. 4 were placed in service, we sold to Georgia Power approximately \$85,951,000 and \$72,600,000, respectively, of 45J 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.

c. Plant Hatch Unit No. 1 and No. 2 and Vogtle Unit No. 1 and No. 2

In December 2025, we recognized receivables of \$180,082,000 from the U.S. Government relating to 45U NPTCs for fiscal years 2024 and 2025 collectively. We intend to defer the benefit of these 45U NPTCs until the three-year IRS statute of limitations has passed and/or completion of an IRS audit for that year's 45U NPTCs. For information regarding this receivable from the U.S. Government and regulatory accounting, see Notes 1f and 1q.

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 \$2,680,000, \$2,324,000 and \$2,143,000 in 2025, 2024 and 2023, 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 \$7,041,000, \$6,251,000 and \$5,655,000 in 2025, 2024 and 2023, 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 \$8,013,000 and \$6,952,000 in 2025 and 2024, 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. We became a member of NEIL and started purchasing accidental outage coverage in April 2023.

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 as of December 31, 2025, based on ownership share is limited to approximately \$52 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 each, 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 2026 for convenience, our cancellation obligation would be approximately \$64,911,000.

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 closure of our coal ash ponds. Expenditures are based on estimates determined through periodic cost 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, 2025, our estimated commitments are as follows:

(dollars in thousands)							
	Coal	Nuclear Fuel	Gas Transportation	Maintenance Agreements	Asset Retirement Obligations	Finance and Operating Leases	
2026	\$ 25,074	\$ 79,860	\$ 75,818	\$ 16,315	\$ 52,185	\$ 17,416	
2027	13,622	27,900	76,779	3,818	44,425	17,139	
2028	7,399	31,500	97,740	53,068	33,229	5,132	
2029	—	25,770	227,038	57,352	41,792	3,695	
2030	—	22,920	225,525	22,794	56,910	3,441	
Thereafter	—	27,300	3,473,182	463,611	10,542,047	2,179	

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. Natural Gas Capacity Agreements:

We have 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 BC Smith. 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. In May 2025, we amended this agreement to reflect final capacity amounts and delivery points. 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 approximately \$1,000,000,000. Our obligation to make payments begins when the pipeline project is placed into service, which is projected to be November 2028.

14. Smarr Combined Cycle Project:

We and our members have approved the development and construction of 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 current budget for this project, which includes capital costs, allowance for funds used during construction and a contingency amount, is \$3.3 billion. The projected commercial operation date is 2029. In September 2025, we entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with TIC – The Industrial Company, a subsidiary of Kiewit Energy Group Inc., for the construction of the project. The EPC Agreement is a fixed price agreement with certain limited exceptions that includes performance guarantees and performance liquidated damages and a parent guaranty by Kiewit. We have separately entered into an agreement with GE Vernova Operations, LLC for the purchase of the two combined cycle units. 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. As of December 31, 2025, we had incurred costs of approximately \$343.5 million with respect to this project.

15. 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. In 2025, we entered into a purchase agreement with the equipment manufacturer for the unit and we expect to enter into a construction agreement for the project in 2026. Our current budget for this unit is approximately \$360 million and the projected commercial operation date is 2029. As of December 31, 2025, we had incurred costs of approximately \$61.5 million with respect to this project.

16. 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.

Other segment expenses are comprised of purchased power, accretion, other income and expense, allowance for debt funds used during construction and amortization of debt discount and expense.

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 and amortization 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.

17. Quarterly financial data (unaudited):

Summarized quarterly financial information for 2025 and 2024 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
(dollars in thousands)				
2025				
Operating revenues	\$ 677,576	\$ 633,748	\$ 631,461	\$ 598,407
Operating margin	162,081	144,897	122,930	106,637
Net margin	43,006	20,295	1,878	(9,824)
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)

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, 2025 and 2024, 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, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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.

Valuation of asset retirement obligations related to nuclear decommissioning

Description of the Matter

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 that are performed periodically and assume the prompt dismantlement and removal of the radiated portions of the plant from service, as well as management of spent fuel. The Company last obtained updated cost studies during the year ended December 31, 2024. At December 31, 2025, the Company's asset retirement obligations related to nuclear decommissioning totaled \$851.8 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 assumed dates of decommissioning and estimated labor, materials and equipment costs.

How We Addressed the Matter in Our Audit

To test the valuation of asset retirement obligations related to nuclear decommissioning, we performed audit procedures with the involvement of engineering specialists, that included, among others, evaluating changes in regulatory requirements, re-licensing expectations and industry trends related to plant closure data used in the most recent cost studies that would impact the significant assumptions described above.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2009.

Atlanta, Georgia
March 27, 2026

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Responsibility for Financial Statements

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

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

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2025 in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information we are required to disclose in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013 framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2025 in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2025, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

During the fiscal quarter ended December 31, 2025, none of our directors or “officers,” as defined in Rule 16a-1(f) under the Securities Exchange Act of 1934, adopted or terminated any “Rule 10b5-1 trading arrangement” or “non-Rule 10b5-1 trading arrangement,” as those terms are defined in Item 408 of Regulation S-K. As noted on the cover page of this annual report, we are a membership corporation and have no authorized or outstanding equity securities although we do have outstanding debt securities.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our Board of Directors

Structure of our Board of Directors

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

Our members will hold their next annual meeting on March 30, 2026. At this meeting, our members will nominate and elect directors to fill the director positions for any director terms ending at that annual meeting and will also have the opportunity to elect a director to fill the vacant outside director position.

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	47	President and Chief Executive Officer
Elizabeth B. Higgins	57	Executive Vice President and Chief Financial Officer
Heather H. Teilhet	50	Executive Vice President, External Affairs
William F. Ussery	61	Executive Vice President, Member Relations
Richard D. Wallen	55	Executive Vice President and Chief Operating Officer
Jami G. Reusch	63	Senior Vice President, Human Resources
Suzanne N. Roberts	43	Senior Vice President and General Counsel
Directors:		
Marshall S. Millwood	76	Chairman and Member Group Director (Group 3)
James I. White	80	Vice-Chairman and Member Group Director (Group 1)
Jimmy G. Bailey	77	At-Large Director
Ronnie M. Hendricks	57	At-Large Director
Horace H. Weathersby III	66	At-Large Director
George L. Weaver	78	Member Group Director (Group 1)
Danny L. Nichols	61	Member Group Director (Group 2)
Sammy G. Simonton	84	Member Group Director (Group 2)
Christopher L. Stephens	57	Member Group Director (Group 3)
Fred A. McWhorter	79	Member Group Director (Group 4)
Jeffrey W. Murphy	62	Member Group Director (Group 4)
Ernest A. "Chip" Jakins III	55	Member Group Director (Group 5)
Kevin W. Bush	41	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 Java Joy and she 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.

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.

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 on March 30, 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.

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 on March 30, 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 the chairman 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 on March 30, 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 GRESCO 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 on March 30, 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 in 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 on March 30, 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 annual report, 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 annual report, 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 annual report, 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." For a discussion regarding our cybersecurity risk oversight, see "CYBERSECURITY".

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.

Insider Trading Policy

We have an Insider Trading Policy that provides guidelines with respect to transactions in our debt securities and the handling of confidential information about us and the companies with which we do business. The policy promotes compliance with U.S. securities laws that prohibit certain persons who are aware of material nonpublic information from purchasing, selling, or otherwise engaging in transactions in our securities, or providing material nonpublic information to other persons who may trade on the basis of that information. The prohibitions against insider trading apply to trading or otherwise transacting in our securities, tipping, and making recommendations to engage in transactions our securities, if the information involved is material and nonpublic. In addition, the prohibitions against insider trading extend to transactions in securities of other companies if the transactions are based on material nonpublic information gained while working for us. As a membership corporation, we do not have any outstanding equity securities although we do have outstanding debt securities. A copy of our board policy prohibiting insider trading is filed as Exhibit 19.1 to this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Executive Summary

The philosophy and objective of our compensation and benefits program is to establish and maintain competitive total compensation programs that will attract, motivate and retain the qualified 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, 2025 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 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 2025, 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 2025, 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 2025, 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. Following the completion of Vogtle Units in 2024, we removed the goals related to Vogtle project and added and increased the weighting of several construction projects at our other plants. The projects weighted most heavily for 2025 were the Smarr combined cycle project and the Talbot and Washington County dual fuel projects. Other projects included the Talbot Unit No. 7 project as well as several other smaller capital projects and upgrades for our existing generation resources. We measure performance based on successful project completion in a timely manner and within project budget.

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 2025, we may earn up to an additional 5% of performance pay by identifying cost savings or reduction strategies above the initial \$52 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 2025, we multiplied 35% of each executive officers' base salary by the corporate goal achievement percentage to determine his or her performance bonus.

Assessment of Performance of 2025 Corporate Goals

The specific corporate performance measures, thresholds, maximums and results for our executive officers' 2025 performance pay were the following:

Performance Category/ Description	Performance Measure	Threshold	Maximum	2025 Result	Weight	Weighted Goal Achieved
Safety						
Incident Rate	Serious Injuries and Fatalities	0	0	100.0 %	3.00 %	3.00 %
Safety Program ⁽¹⁾	Safety Training and Meetings	100.0 %	100.0 %	100.0 %	1.00 %	1.00 %
	Safety Observation Program	300/240	500/400	100.0 %	2.00 %	2.00 %
	Diversity of Observation Contributors	120	200	100.0 %	0.50 %	0.50 %
	Hazard Reduction Program	75.0 %	100.0 %	100.0 %	0.50 %	0.50 %
Operations⁽²⁾						
Oglethorpe Managed	Successful Starts	99.0 %	100.0 %	99.5 %	3.00 %	2.92 %
	Peak Season Availability	68.5 %	99.8 %	84.6 %	23.00 %	19.43 %
Co-Owned Fleet	Coal Fleet Peak Season Equivalent Forced Outage Rate	6.0 %	3.0 %	100.0 %	0.65 %	0.65 %
	Coal Fleet Annual Equivalent Unplanned Unavailability Factor	5.8 %	3.3 %	50.0 %	0.35 %	0.18 %
	Nuclear Fleet Capability Factor	91.0 %	93.0 %	93.1 %	3.00 %	3.00 %
Construction and Project Management						
Oglethorpe New Generation Construction	Status of Projects	Meet applicable deadlines		100.0 %	6.00 %	6.00 %
Oglethorpe Existing Fleet Projects	Status of Projects	Meet applicable deadlines & budgets		85.8 %	13.00 %	11.16 %
Corporate Compliance						
Environmental	Final Notices of Violation and Letters of Non-Compliance	1 (if fine is ≤ \$5,000) or 2	0	0	4.00 %	4.00 %
	Reportable Spills	1	0	0	4.00 %	4.00 %
Mandatory Electric Reliability Standards	Non-Critical Infrastructure Protection Compliance	1+ (if minimal penalty)	0	0	2.00 %	2.00 %
	Critical Infrastructure Protection Compliance	1+ (if minimal penalty)	0	0	3.00 %	3.00 %
Financial						
Cost Saving	Current Year / Long-Term Savings	\$ 0	\$52,000,000	\$53,095,614	14.00 %	14.00 %
	Additional Cost Savings	\$ 0	\$50,000,000	\$46,543,196	0-5.0%	4.65 %
Internal Control over Financial Reporting	Significant Deficiency Or Material Weakness	0	0	0.00	2.00 %	2.00 %
	Control Deficiency resulting in immaterial misstatement of Audit Committee disclosure	2	0	0.00	1.00 %	1.00 %
Quality						
Board Satisfaction	Board of Directors Survey	80.0 %	100.0 %	96.40 %	14.00 %	13.50 %
Total					100.00 %	98.49 %

(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 98.49% of our corporate goals for 2025. As a result, Ms. Bloodworth, Ms. Higgins, Mr. Wallen, Mr. Ussery and Ms. Teilhet received performance pay in an amount equal to 98.49% of 35% 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 2025:

Executive Officer	Performance Pay*
Annalisa M. Bloodworth	\$ 312,312
Elizabeth B. Higgins	240,556
Richard D. Wallen	137,800
William F. Ussery	170,334
Heather H. Teilhet	160,000

* Performance pay was calculated based on base salaries as of December 31, 2025. Actual compensation earned in 2025 is reported in the Summary Compensation Table below.

Employment Agreements

General

We have an employment agreement with Ms. Bloodworth, Ms. Higgins, Ms. Teilhet, Mr. Ussery and Mr. Wallen. 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, 2028. 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, Ms. Teilhet, Mr. Ussery and Mr. Wallen. The current term of Ms. Higgins', Ms. Teilhet's and Mr. Ussery's agreements extends through December 31, 2028 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. The current term of Mr. Wallen's agreement 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 twelve months before the expiration of any extended term. Each year, our president and chief executive officer makes an affirmative determination as to whether to provide such notice, and no such notices have been provided.

Minimum annual base salaries under these agreements are \$671,000 for Ms. Higgins, \$406,300 for Ms. Teilhet, \$470,600 for Mr. Ussery and \$533,000 for Mr. Wallen. 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, Ms. Teilhet, Mr. Ussery and Mr. Wallen contain severance pay provisions.

We also have 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 \$2,084,710.

Our president and chief executive officer considered the total amount of compensation Ms. Higgins, Ms. Teilhet, Mr. Ussery and Mr. Wallen would receive upon the occurrence of a severance event and determined that it was appropriate for Ms. Higgins, Ms. Teilhet and Mr. Ussery to receive severance compensation equal to a maximum of two years of his or her then current base salary and for Mr. Wallen to receive severance compensation equal to of one year of his 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, Ms. Teilhet, Mr. Ussery and Mr. Wallen 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 for Ms. Higgins, Ms. Teilhet and Mr. Ussery 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. The severance payment for Mr. Wallen will equal his then current base salary of one year's pay and an amount equal to his cost for medical and dental continuation coverage under COBRA for six months 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, Ms. Teilhet, Mr. Ussery and Mr. Wallen in the circumstances described above is \$1,533,979, \$1,047,554, \$1,079,786 and \$641,438, respectively.

Compensation Committee Report

The Compensation Committee of Oglethorpe Power Corporation has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2025 for filing with the SEC.

Respectfully Submitted
The Compensation Committee

Earnest A. Jakins III
Jimmy G. Bailey
Fred A. McWhorter
Danny L. Nichols
Christopher L. Stephens
Horace H. Weathersby III

Compensation Committee Interlocks and Insider Participation

Mr. Jakins, Mr. Bailey, Mr. McWhorter, Mr. Millwood, Mr. Nichols, Mr. Stephens and Mr. Weathersby served as members of our compensation committee during all or a portion of 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 \$457.9 million to us in 2025 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 \$52.5 million to us in 2025 under its wholesale power contract accounted for approximately 2.1% 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 \$111.5 million to us in 2025 under its wholesale power contract accounted for approximately 4.4% 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, 2025, 2024 and 2023.

Name and Principal Position	Year	Salary	Bonus	Non-Equity Incentive Plan Compensation	All Other Compensation ⁽¹⁾	Total
Annalisa M. Bloodworth⁽²⁾	2025	\$ 870,750	\$ —	\$ 312,312	\$ 199,212	\$ 1,382,274
President and	2024	478,000	—	142,190	126,503	746,693
Chief Executive Officer	2023	438,333	—	130,654	107,364	676,351
Michael L. Smith⁽³⁾	2025	90,307	—	—	351,361	441,668
Former President and	2024	1,072,663	—	372,198	233,401	1,678,262
Chief Executive Officer	2023	1,007,450	—	342,394	196,817	1,546,661
Elizabeth B. Higgins	2025	689,200	—	240,556	351,171	1,280,927
Executive Vice President and	2024	614,667	—	213,286	133,479	961,432
Chief Financial Officer	2023	578,333	—	196,174	118,561	893,068
Richard D. Wallen⁽⁴⁾	2025	534,017	—	137,800	76,331	748,148
Executive Vice President and Chief Operating Officer						
William F. Ussery	2025	478,806	—	170,334	107,757	756,897
Executive Vice President,	2024	466,016	—	138,540	112,740	717,296
Member Relations	2023	439,583	—	127,799	93,720	661,102
Heather H. Teilhet	2025	457,843	—	160,000	115,951	733,794
Executive Vice President, External Affairs						
David W. Sorrick⁽⁵⁾	2025	24,166	—	—	1,337,248	1,361,414
Former Executive Vice President	2024	574,333	—	199,204	126,800	900,337
Chief Operating Officer	2023	541,667	—	183,724	110,200	835,591

(1) Figures for 2025 consist of matching contributions and contributions we made under the 401(k) Retirement Savings Plan on behalf of Ms. Bloodworth, Ms. Higgins, Mr. Ussery, Ms. Teilhet, and Mr. Smith of \$46,500; Mr. Wallen of \$51,053, and Mr. Sorrick of \$46,037, contributions by Oglethorpe to a nonqualified deferred compensation plan on behalf of Ms. Bloodworth, Ms. Higgins, Mr. Wallen, Mr. Ussery, Ms. Teilhet, Mr. Smith and Mr. Sorrick, respectively, of \$122,215, \$113,259, \$14,589, \$64,112, \$50,966, \$105,755 and \$20,159; car allowances; paid time off, executive health benefits; customary holiday gifts and service awards. Amounts for Ms. Higgins in 2025 also include a payment of \$200,000 under our retention agreement with Ms. Higgins. Amounts for Mr. Sorrick in 2025 also include payment of \$1,205,427 for severance and medical and dental insurance continuation coverage made in accordance with the terms of Mr. Sorrick's employment agreement. The 2025 amounts for Mr. Smith and Mr. Sorrick also include payments of \$191,557 and \$65,250, respectively, for unused paid time off in accordance with our policy.

(2) Ms. Bloodworth was our Senior Vice President and General Counsel through January 31, 2025 and assumed the role of President and Chief Executive Officer on February 1, 2025.

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

(4) Mr. Wallen joined Oglethorpe on March 31, 2025.

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

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards	
		Threshold	Maximum
Annalisa M. Bloodworth	N/A	\$ 96,076	\$ 317,100
Elizabeth B. Higgins	N/A	\$ 74,002	\$ 244,244
Richard D. Wallen	N/A	\$ 56,522	\$ 186,550
William F. Ussery	N/A	\$ 52,400	\$ 172,946
Heather H. Teilhet	N/A	\$ 49,221	\$ 162,453

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 2025 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, 2025 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
Annalisa M. Bloodworth	\$ 39,720	\$ 122,215	\$ 55,327	\$ —	\$ 528,659
Elizabeth B. Higgins	\$ 24,797	\$ 113,259	\$ 207,688	\$ —	\$ 1,691,491
Richard D. Wallen	\$ 11,008	\$ 14,589	\$ 692	\$ —	\$ 26,289
William F. Ussery	\$ 3,000	\$ 64,112	\$ 85,624	\$ —	\$ 717,539
Heather H. Teilhet	\$ 8,640	\$ 50,966	\$ 22,688	\$ —	\$ 207,798
Former Executive Officers:					
Michael L. Smith	\$ 7,292	\$ 105,755	\$ 269,253	\$ (413,294)	\$ 2,014,884
David W. Sorrick	\$ 533	\$ 20,159	\$ 19,548	\$ (34,743)	\$ 145,463

- (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 Ms. Bloodworth, our president and chief executive officer during 2025, to the annual total compensation of our median employee for the fiscal year ended December 31, 2025.

To identify our median employee, we determined that as of December 31, 2025, we had 401 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, 2025 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 2025 was \$175,194. As set forth in the Summary Compensation Table, our president and chief executive officer's annual total compensation for 2025 was \$1,382,274. 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, 2025 was 7.89:1.

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, 2025.

Name	Total Fees Earned or Paid in Cash
Member Directors	
Jimmy G. Bailey	\$ 44,770
Randy Crenshaw ⁽¹⁾	\$ 6,425
Ronnie M. Hendricks ⁽²⁾	\$ 37,600
Ernest A. "Chip" Jakins III	\$ 40,250
Fred A. McWhorter	\$ 39,670
Marshall S. Millwood, Chairman	\$ 55,265
Jeffrey W. Murphy	\$ 42,875
Danny L. Nichols	\$ 41,650
Sammy G. Simonton	\$ 44,595
Christopher L. Stephens ⁽²⁾	\$ 34,450
Horace H. Weathersby III	\$ 44,770
George L. Weaver	\$ 45,675
James I. White, Vice-Chairman	\$ 47,195
Outside Directors	
Wm. Ronald Duffey ⁽¹⁾	\$ 12,405
Kevin W. Bush ⁽²⁾	\$ 70,880

(1) Mr. Crenshaw and Mr. Duffey each served on our board of directors until the annual meeting of our members on March 31, 2025.

(2) Mr. Bush, Mr. Hendricks and Mr. Stephens were each elected to our board of directors at the annual meeting of our members on March 31, 2025.

In 2025, we paid our member directors a per diem of \$3,700 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 \$8,400 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.

The audit committee is directly responsible for oversight of our financial reporting functions and for the auditor reports included in our SEC quarterly and annual filings. Directors on the audit committee that attend an audit committee meeting pertaining to a quarterly SEC filing will be paid \$1,400 regardless of whether the meeting is in person or virtual. Directors attending a board of directors meeting pertaining to a quarterly or annual SEC filing will be paid \$1,400 regardless of whether the meeting is in person or virtual. If a board and committee meeting on a quarterly or annual SEC filing occur on the same day and

both the board and committee meeting are exclusively to consider the SEC filing, the director compensation will be capped at \$1,400 per director for the day.

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.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

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 \$457.9 million to us in 2025 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 \$36.7 million to us in 2025 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 \$52.5 million to us in 2025 under its wholesale power contract accounted for approximately 2.1% 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 \$111.5 million to us in 2025 under its wholesale power contract accounted for approximately 4.4% 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 \$99.4 million to us in 2025 under its wholesale power contract accounted for approximately 3.9% of our total revenues.

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

Director Independence

Because we are an electric cooperative, 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, 2025. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria in making this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

For 2025 and 2024, fees for services provided by our independent registered public accounting firm, Ernst & Young LLP were as follows:

	2025	2024
	(dollars in thousands)	
Audit Fees ⁽¹⁾	\$ 879	\$ 745
Audit-Related Fees ⁽²⁾	277	142
All Other Fees ⁽³⁾	5	—
Total	\$ 1,161	\$ 887

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

(2) Other audit-related services.

(3) All other fees related to a subscription of an online accounting research and investigative tool.

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

Pre-Approval Policy

The audit and permissible non-audit services performed by Ernst & Young LLP in 2025 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. The policy requires that requests for all services must be submitted to the audit committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

	<u>Page</u>
(1) Financial Statements (Included under "Financial Statements and Supplementary Data")	
Consolidated Statements of Revenues and Expenses, For the Years Ended December 31, 2025, 2024 and 2023	59
Consolidated Balance Sheets, As of December 31, 2025 and 2024	60
Consolidated Statements of Capitalization, As of December 31, 2025 and 2024	62
Consolidated Statements of Cash Flows, For the Years Ended December 31, 2025, 2024 and 2023	63
Consolidated Statements of Patronage Capital and Membership Fees, For the Years Ended December 31, 2025, 2024 and 2023	64
Notes to Consolidated Financial Statements	65
Report of Independent Registered Public Accounting Firm	98
(2) Financial Statement Schedules	
None applicable.	
(3) Exhibits	

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

Number	Description
*3.1(a)	– Restated Articles of Incorporation of Oglethorpe, dated as of July 26, 1988. (Filed as Exhibit 3.1 to the Registrant's Form 10-K for the fiscal year ended December 31, 1988, File No. 33-7591.)
*3.1(b)	– Amendment to Articles of Incorporation of Oglethorpe, dated as of March 11, 1997. (Filed as Exhibit 3(i)(b) to the Registrant's Form 10-K for the fiscal year ended December 31, 1996, File No. 33-7591.)
*3.2	– Bylaws of Oglethorpe, as amended and restated, as of 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	– Fourteenth Amended and Restated Loan Contract, dated as of February 24, 2026, between Oglethorpe and the United States of America.
*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 4.1\(mmmm\) to the Registrant's Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.\)](#)
- 4.2.1(nnnn) – [Ninety-First Supplemental Indenture, dated as of November 18, 2025, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to subjecting, conveying and confirming the lien of the indenture with respect to certain agreements, instruments, other documents and property.](#)
- 4.2.1(oooo) – [Ninety-Second Supplemental Indenture, dated as of December 11, 2025, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to subjecting, conveying and confirming the lien of the indenture with respect to certain agreements, instruments, other documents and property.](#)
- 4.2.1(pppp) – [Ninety-Third Supplemental Indenture, dated as of February 24, 2026, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to relating to the Series 2026 \(FFB AK48\) Note, Series 2026 \(RUS AK48\) Reimbursement Note.](#)

- *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(a) – [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(b) – [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. \(Filed as Exhibit 4.4 to the Registrant's Form 8-K filed on March 27, 2019, File No. 333-192954.\)](#)
- *10.1.1(a) – Participation Agreement No. 2 among Oglethorpe as Lessee, Wilmington Trust Company as Owner Trustee, The First National Bank of Atlanta as Indenture Trustee, Columbia Bank for Cooperatives as Loan Participant and Ford Motor Credit Company as Owner Participant, dated December 30, 1985, together with a schedule identifying three other substantially identical Participation Agreements. (Filed as Exhibit 10.1.1(b) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
- *10.1.1(b) – Supplemental Participation Agreement No. 2. (Filed as Exhibit 10.1.1(a) to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)
- *10.1.1(c) – Supplemental Participation Agreement No. 1, dated as of June 30, 1987, among Oglethorpe as Lessee, IBM Credit Financing Corporation as Owner Participant, Wilmington Trust Company and The Citizens and Southern National Bank as Owner Trustee, The First National Bank of Atlanta, as Indenture Trustee, and Columbia Bank for Cooperatives, as Loan Participant. (Filed as Exhibit 10.1.1(c) to the Registrant's Form 10-K for the fiscal year ended December 31, 1987, File No. 33-7591.)
- *10.1.1(d) – [Second Supplemental Participation Agreement No. 2, dated as of December 17, 1997, among Oglethorpe as Lessee, DFO Partnership, as assignee of Ford Motor Credit Company, as Owner Participant, Wilmington Trust Company and NationsBank, N.A. as Owner Trustee, The Bank of New York Trust Company of Florida, N.A. as Indenture Trustee, CoBank, ACB as Loan Participant, OPC Scherer Funding Corporation, as Original Funding Corporation, OPC Scherer 1997 Funding Corporation A, as Funding Corporation, and SunTrust Bank, Atlanta, as Original Collateral Trust Trustee and Collateral Trust Trustee, with a schedule identifying three substantially identical Second Supplemental Participation Agreements and any material differences. \(Filed as Exhibit 10.1.1\(d\) to Registrant's Form S-4 Registration Statement, File No. 333-4275.\)](#)
- *10.1.2 – General Warranty Deed and Bill of Sale No. 2 between Oglethorpe, Grantor, and Wilmington Trust Company and William J. Wade, as Owner Trustees under Trust Agreement No. 2, dated December 30, 1985, with Ford Motor Credit Company, Grantee, together with a schedule identifying three substantially identical General Warranty Deeds and Bills of Sale. (Filed as Exhibit 10.1.2 to the Registrant's Form S-1 Registration Statement, File No. 33-7591.)

- *10.1.3 – [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.\)](#)
- *10.4.1 – [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 \(An Electric Membership Corporation\). \(Filed as Exhibit 10.17.1\(b\) to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006, File No. 33-7591.\)](#)
- *10.10.1(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⁽²⁾ – [Amended and Restated Employment Agreement, dated as of November 5, 2024, between Oglethorpe and Annalisa M. Bloodworth. \(Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 12, 2024, File No. 333-192954.\)](#)

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*10.14(a) ⁽²⁾	–	<u>Amended and Restated Employment Agreement, dated as of January 1, 2025, between Oglethorpe and Elizabeth B. Higgins. (Filed as Exhibit 10.14(a) to the Registrant’s Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.)</u>
*10.14(b) ⁽²⁾	–	<u>Retention Incentive Agreement, dated as of December 9, 2024, between Oglethorpe and Elizabeth B. Higgins. (Filed as Exhibit 10.14(b) to the Registrant’s Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.)</u>
*10.15 ⁽²⁾	–	<u>Amended and Restated Employment Agreement, dated as of January 1, 2025, between Oglethorpe and William F. Ussery. (Filed as Exhibit 10.15 to the Registrant’s Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.)</u>
10.16 ⁽²⁾	–	<u>Amended and Restated Employment Agreement, dated as of January 1, 2025, between Oglethorpe and Heather H. Teilhet.</u>
10.17 ⁽²⁾	–	<u>Employment Agreement, dated as of January 1, 2026, between Oglethorpe and Richard D. Wallen.</u>
14.1	–	Code of Conduct, available on our website, www.opc.com .
*19.1	–	<u>Insider Trading Policy (Filed as Exhibit 19.1 to the Registrant’s Form 10-K for the fiscal year ended December 31, 2024, File No. 333-192954.)</u>
31.1	–	<u>Rule 13a-14(a)/15d-14(a) Certification, by Annalisa M. Bloodworth (Principal Executive Officer).</u>
31.2	–	<u>Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).</u>
32.1	–	<u>Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Annalisa M. Bloodworth (Principal Executive Officer).</u>
32.2	–	<u>Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).</u>
*99.1	–	<u>Member Financial and Statistical Information. (Filed as Exhibit 99.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2025, File No. 333-192954.)</u>
101	–	XBRL Interactive Data File.
104	–	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101).

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

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of March, 2026.

OGLETHORPE POWER CORPORATION
(AN ELECTRIC MEMBERSHIP CORPORATION)

By: /s/ ANNALISA M. BLOODWORTH
ANNALISA M. BLOODWORTH
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ ANNALISA M. BLOODWORTH</u> ANNALISA M. BLOODWORTH	President and Chief Executive Officer (Principal Executive Officer)	March 27, 2026
<u>/s/ ELIZABETH B. HIGGINS</u> ELIZABETH B. HIGGINS	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 27, 2026
<u>/s/ KATHRYN N. CURTIS</u> KATHRYN N. CURTIS	Vice President, Controller (Principal Accounting Officer)	March 27, 2026
<u>/s/ JIMMY G. BAILEY</u> JIMMY G. BAILEY	Director	March 27, 2026
<u>/s/ KEVIN W. BUSH</u> KEVIN W. BUSH	Director	March 27, 2026
<u>/s/ RONNIE M. HENDRICKS</u> RONNIE M. HENDRICKS	Director	March 27, 2026
<u>/s/ ERNEST A. JAKINS III</u> ERNEST A. JAKINS III	Director	March 27, 2026
<u>/s/ FRED MCWHORTER</u> FRED MCWHORTER	Director	March 27, 2026

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ MARSHALL S. MILLWOOD</u> MARSHALL S. MILLWOOD	Director	March 27, 2026
<u>/s/ JEFFREY W. MURPHY</u> JEFFREY W. MURPHY	Director	March 27, 2026
<u>/s/ DANNY L. NICHOLS</u> DANNY L. NICHOLS	Director	March 27, 2026
<u>/s/ SAMMY G. SIMONTON</u> SAMMY G. SIMONTON	Director	March 27, 2026
<u>/s/ CHRISTOPHER L. STEPHENS</u> CHRISTOPHER L. STEPHENS	Director	March 27, 2026
<u>/s/ HORACE H. WEATHERSBY III</u> HORACE H. WEATHERSBY III	Director	March 27, 2026
<u>/s/ GEORGE L. WEAVER</u> GEORGE L. WEAVER	Director	March 27, 2026
<u>/s/ JAMES I. WHITE</u> JAMES I. WHITE	Director	March 27, 2026