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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2026

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**

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). **Yes** ☒ **No** ☐

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

Large Accelerated Filer ☐ **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 is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ☐ **No** ☒

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

Title of each class:	Trading Symbol(s)	Name of each exchange on which registered:
None	N/A	N/A

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.**

OGLETHORPE POWER CORPORATION

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FOR THE QUARTER ENDED JUNE 30, 2026

CAUTIONARY STATEMENT REGARDING

FORWARD-LOOKING INFORMATION

This quarterly report on Form 10-Q 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 "Item 1A—RISK FACTORS" and in other sections of our annual report on Form 10-K for the fiscal year ended December 31, 2025, and in this quarterly report on Form 10-Q. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this quarterly report may not occur.

Any forward-looking statement speaks only as of the date of this quarterly 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 from the development and deployment of distributed generation and energy storage technologies;
- the inability of counterparties to meet their obligations to us or our members, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- our members' ability to offer their residential, commercial and industrial customers competitive rates;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption (including from data centers and other large commercial and industrial loads), energy conservation and efficiency efforts and the general economy;
- general economic conditions;
- tariffs and geopolitical trade tensions;
- weather conditions and other natural phenomena;
- litigation or legal and administrative proceedings and settlements;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- early retirement of our co-owned coal units;
- acts of sabotage, wars or terrorist activities, including cyber attacks;
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards;
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, 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 quarterly report and in other reports we file with the SEC.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
June 30, 2026 and December 31, 2025

	(dollars in thousands)	
	2026	2025
Assets		
Electric plant:		
In service	**$ 17,767,534**	$ 17,663,646
Right-of-use assets—finance leases	**302,732**	302,732
Less: Accumulated provision for depreciation	**(6,100,740)**	(5,933,906)
Electric plant in service, net	**11,969,526**	12,032,472
Nuclear fuel, at amortized cost	**428,604**	408,556
Construction work in progress	**1,146,688**	787,886
Total electric plant	**13,544,818**	13,228,914
Investments and funds:		
Nuclear decommissioning trust fund	**933,447**	855,223
Investment in associated companies	**95,162**	91,378
Long-term investments	**646,344**	653,265
Other	**43,262**	42,111
Total investments and funds	**1,718,215**	1,641,977
Current assets:		
Cash and cash equivalents	**121,592**	251,119
Restricted cash and short-term investments	**500**	500
Short-term investments	**66,161**	80,164
Receivables	**399,733**	397,059
Inventories, at weighted average cost	**408,183**	372,765
Prepayments and other current assets	**43,227**	45,472
Total current assets	**1,039,396**	1,147,079
Deferred charges and other assets:		
Regulatory assets	**1,037,131**	1,023,859
Prepayments to Georgia Power Company	**16,679**	22,419
Other	**84,609**	85,551
Total deferred charges	**1,138,419**	1,131,829
Total assets	**$ 17,440,848**	$ 17,149,799

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

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
June 30, 2026 and December 31, 2025

	(dollars in thousands)	
	2026	2025
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 1,448,146**	$ 1,383,773
Long-term debt	**12,082,135**	12,065,863
Obligation under finance leases	**15,295**	21,578
Obligation under Rocky Mountain transactions	**35,249**	34,099
Other	**4,323**	5,284
Total capitalization	**13,585,148**	13,510,597
Current liabilities:		
Long-term debt and finance leases due within one year	**401,952**	391,726
Short-term borrowings	**732,809**	459,513
Accounts payable	**130,218**	248,499
Accrued interest	**87,006**	91,146
Member power bill prepayments, current	**24,389**	28,453
Other current liabilities	**202,500**	215,193
Total current liabilities	**1,578,874**	1,434,530
Deferred credits and other liabilities:		
Asset retirement obligations	**1,290,636**	1,280,941
Member power bill prepayments, non-current	**34,400**	38,300
Regulatory liabilities	**931,187**	869,860
Other	**20,603**	15,571
Total deferred credits and other liabilities	**2,276,826**	2,204,672
Total equity and liabilities	**$ 17,440,848**	$ 17,149,799

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

Oglethorpe Power Corporation
Consolidated Statements of Revenues and Expenses (Unaudited)
For the Three and Six Months Ended June 30, 2026 and 2025

	(dollars in thousands)			
	Three Months		Six Months	
	2026	2025	**2026**	2025
Operating revenues:				
Sales to members	**$ 574,157**	$ 601,690	**$ 1,281,158**	$ 1,269,991
Sales to non-members	**15,313**	32,058	**45,368**	41,333
Total operating revenues	**589,470**	633,748	**1,326,526**	1,311,324
Operating expenses:				
Fuel	**173,274**	186,838	**458,665**	429,485
Production	**132,069**	157,956	**271,856**	288,284
Depreciation and amortization	**111,444**	107,341	**222,052**	213,598
Purchased power	**23,305**	22,109	**46,000**	43,840
Accretion	**14,794**	14,607	**29,506**	29,139
Total operating expenses	**454,886**	488,851	**1,028,079**	1,004,346
Operating margin	**134,584**	144,897	**298,447**	306,978
Other income:				
Investment income	**7,569**	8,047	**14,730**	16,544
Other	**3,143**	492	**8,634**	4,051
Total other income	**10,712**	8,539	**23,364**	20,595
Interest charges:				
Interest expense	**136,778**	135,537	**271,477**	267,971
Allowance for debt funds used during construction	**(10,187)**	(4,991)	**(19,001)**	(8,719)
Amortization of debt discount and expense	**2,481**	2,595	**4,962**	5,020
Net interest charges	**129,072**	133,141	**257,438**	264,272
Net margin	**$ 16,224**	$ 20,295	**$ 64,373**	$ 63,301

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

Oglethorpe Power Corporation
Consolidated Statements of Patronage Capital and Membership Fees (Unaudited)
For the Three and Six Months Ended June 30, 2026 and 2025

		(dollars in thousands)
Balance at December 31, 2024	$	1,328,418
Net margin		43,006
Balance at March 31, 2025	$	1,371,424
Net margin		20,295
Balance at June 30, 2025	$	1,391,719
Balance at December 31, 2025	$	1,383,773
Net margin		48,149
Balance at March 31, 2026	$	1,431,922
Net margin		**16,224**
Balance at June 30, 2026	**$**	**1,448,146**

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

Oglethorpe Power Corporation
Consolidated Statements of Cash Flows (Unaudited)
For the Six Months Ended June 30, 2026 and 2025

	(dollars in thousands)	
	2026	2025
Cash flows from operating activities:		
Net margin	**$ 64,373**	$ 63,301
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**305,235**	297,789
Accretion cost	**29,506**	29,139
Amortization of deferred gains	**(894)**	(894)
Allowance for equity funds used during construction	**(1,233)**	(1,377)
Deferred outage costs	**(38,716)**	(23,434)
Loss (gain) on sale of investments	**1,762**	(183)
Regulatory deferral of costs associated with nuclear decommissioning	**(145)**	3,455
Other	**4,535**	(12,802)
Change in operating assets and liabilities:		
Receivables	**5,403**	(36,118)
Inventories	**(35,419)**	17,009
Prepayments and other current assets	**(9,661)**	(3,661)
Accounts payable	**(45,993)**	(27,233)
Accrued interest	**(4,140)**	9,294
Accrued taxes	**(27,271)**	(15,928)
Settlement of asset retirement obligations	**(19,725)**	(16,366)
Other current liabilities	**(19,801)**	(4,997)
Rate management program billing credits applied	**(38,252)**	(58,600)
Other	**(7,963)**	(3,460)
Total adjustments	**97,228**	151,633
Net cash provided by operating activities	**161,601**	214,934
Cash flows from investing activities:		
Property additions	**(623,725)**	(388,104)
Litigation proceeds received for capitalized spent nuclear fuel storage costs	**—**	21,684
Activity in nuclear decommissioning trust fund—Purchases	**(689,723)**	(523,182)
Activity in nuclear decommissioning trust fund—Proceeds	**675,831**	509,464
Activity in long-term and short-term investments—Purchases	**(182,196)**	(126,191)
Activity in long-term and short-term investments—Proceeds	**218,421**	198,503
Other	**1,369**	(928)
Net cash used in investing activities	**(600,023)**	(308,754)
Cash flows from financing activities:		
Long-term debt proceeds	**175,713**	418,435
Long-term debt payments	**(503,215)**	(209,568)
Increase (decrease) in commercial paper borrowings, net	**614,601**	(173,887)
Other	**21,796**	(14,781)
Net cash provided by financing activities	**308,895**	20,199
Net decrease in cash, cash equivalents and restricted cash	**(129,527)**	(73,621)
Cash, cash equivalents and restricted cash at beginning of period	**251,619**	338,313
Cash, cash equivalents and restricted cash at end of period	**$ 122,092**	$ 264,692
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 255,466**	$ 248,882
Supplemental disclosure of non-cash investing and financing activities:		
Accrued property additions at end of period	**$ 150,672**	$ 89,282

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

(A) *General.* The consolidated financial statements included in this report have been prepared by us pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the information furnished in this report reflects all adjustments (which include only normal recurring adjustments) and estimates necessary to fairly state, in all material respects, our financial condition and results of operations for the three-month and six-month periods ended June 30, 2026 and 2025. Examples of estimates used include items related to (i) our asset retirement obligations, such as closure and post-closure cost estimates, timing of expenditures, escalation factors and discount rates, and (ii) depreciation rates, such as determining the depreciable service lives. Actual results could differ from our estimates. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to SEC rules and regulations, although we believe that the disclosures are adequate to make the information presented not misleading.

These unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2025, as filed with the SEC. The results of operations for the three-month and six-month periods ended June 30, 2026 are not necessarily indicative of results to be expected for the full year. As noted in our 2025 Form 10-K, our revenues consist primarily of sales to our 38 electric distribution cooperative members and, thus, the receivables on the consolidated balance sheets are principally from our members. See "Notes to Consolidated Financial Statements" in our 2025 Form 10-K.

(B) *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.

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

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

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

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

The tables below detail assets and liabilities measured at fair value on a recurring basis at June 30, 2026 and December 31, 2025.

	Fair Value Measurements at Reporting Date Using			
		Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
	June 30, 2026	(Level 1)	(Level 2)	(Level 3)
	(dollars in thousands)			
Nuclear decommissioning trust funds:				
Domestic equity	**$ 279,655**	$ 279,655	$ —	$ —
Corporate bonds and debt	**119,822**	—	119,642	180
US Treasury securities	**85,160**	85,160	—	—
Mortgage backed securities	**62,722**	—	62,722	—
Domestic mutual funds	**132,450**	132,450	—	—
Municipal bonds	**3,764**	—	3,764	—
Federal agency securities	**8,093**	—	8,093	—
Non-US Gov't bonds & private placements	**19,756**	—	19,756	—
International mutual funds	**206,888**	—	206,888	—
Other	**15,137**	15,137		
Long-term investments:				
Corporate bonds and debt	**30,021**	—	30,021	—
US Treasury securities	**44,025**	44,025	—	—
Mortgage backed securities	**24,810**	—	24,810	—
Domestic mutual funds	**434,624**	434,624	—	—
Treasury STRIPS	**53,584**	—	53,584	—
Non-US Gov't bonds & private placements	**3,039**	—	3,039	—
International mutual funds	**55,829**	—	55,829	—
Other	**412**	412	—	—
Short-term investments: Treasury STRIPS	**66,161**	—	66,161	—
Natural gas swaps	**15,176**	—	15,176	—

	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	—

The Level 2 investments above may not be exchange traded. The fair value measurements for these investments are based on a market approach, including the use of observable inputs at or near the valuation date. 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 June 30, 2026 and December 31, 2025 were as follows:

	2026		2025	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
	(in thousands)			
Long-term debt	**$ 12,585,504**	**$ 10,920,819**	$ 12,566,059	$ 11,008,470

The estimated fair value of long-term debt is classified as Level 2 and is estimated based on observed or quoted market prices for the same or similar issues or on current rates offered to us for debt of similar maturities. The primary sources of our long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank that is guaranteed by the Rural Utilities Service or the U.S. Department of Energy. 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 June 30, 2026 and 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 and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments.

(C) *Derivative Instruments.* We use commodity derivatives to manage our exposure to fluctuations 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 statement 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 June 30, 2026, 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 June 30, 2026 and December 31, 2025, the estimated fair values of our natural gas contracts were net liabilities and net assets of approximately $15,176,000 and $10,642,000, respectively.

At June 30, 2026 and December 31, 2025, 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 item within our unaudited consolidated balance sheets.

The following table reflects the notional volume of our natural gas derivatives as of June 30, 2026 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2026	17.7
2027	32.6
2028	24.8
2029	23.3
2030	20.1
2031	12.5
Total	**131.0**

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 June 30, 2026 and December 31, 2025. 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					
		2026			2025		
		Assets	**Liabilities**	**Net Carrying Value Presented on the Balance Sheet**	**Assets**	**Liabilities**	**Net Carrying Value Presented on the Balance Sheet**
Assets		(dollars in thousands)					
Natural gas swaps	Other current assets	**$ 715**	**$ (352)**	**$ 363**	$ 14,775	$ (2,505)	$ 12,270
Natural gas swaps	Other deferred charges	**—**	**—**	**—**	3,084	(1,251)	1,833
Liabilities							
Natural gas swaps	Other current liabilities	**$ 4,703**	**$ (11,299)**	**$ (6,596)**	$ 145	$ (435)	$ (290)
Natural gas swaps	Other deferred credits	**1,319**	**(10,262)**	**(8,943)**	1,020	(4,191)	(3,171)
Total		**$ 6,737**	**$ (21,913)**	**$ (15,176)**	$ 19,024	$ (8,382)	$ 10,642

The following table presents the gross realized gains and (losses) on derivative instruments recognized in net margins for the three and six months ended June 30, 2026 and 2025.

	Statement of Revenues and Expenses Location	Three Months Ended June 30,		Six Months Ended June 30,	
		2026	2025	**2026**	2025
		(dollars in thousands)			
Natural gas swaps gains	Fuel	**$ 1,071**	$ 5,592	**$ 10,230**	$ 7,958
Natural gas swaps losses	Fuel	**(1,310)**	(1,036)	**(2,994)**	(2,395)
Total		**$ (239)**	$ 4,556	**$ 7,236**	$ 5,563

The following table presents the unrealized gains on derivative instruments deferred on the balance sheet at June 30, 2026 and December 31, 2025.

	Balance Sheet Location	**2026**	2025
		(dollars in thousands)	
Natural gas swaps	Regulatory asset	**$ 15,176**	$ —
Natural gas swaps	Regulatory liability	**$ —**	$ 10,642
Total		**$ 15,176**	$ 10,642

(D) *Investment 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 as of June 30, 2026 and December 31, 2025.

		Gross Unrealized		
		(dollars in thousands)		
June 30, 2026	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 420,541**	**$ 396,783**	**$ (4,921)**	**$ 812,403**
Debt	**819,701**	**10,100**	**(11,797)**	**818,004**
Other	**15,284**	**685**	**(424)**	**15,545**
Total	**$ 1,255,526**	**$ 407,568**	**$ (17,142)**	**$ 1,645,952**

		Gross Unrealized		
		(dollars in thousands)		
December 31, 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

The cost basis of our debt securities that were in unrealized loss positions at June 30, 2026 was $610,379,000. At June 30, 2026, $2,190,000 of the $11,797,000 of unrealized losses relates to securities that have been in unrealized loss positions for less than twelve months and $9,607,000 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 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.

(E) *Recently Issued or Adopted Accounting Pronouncements.* 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.

(F) *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 that extend to December 31, 2085. These contracts 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 the 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 June 30, 2026 and December 31, 2025, we did not have any significant long-term contracts with non-members.

The consideration we receive for providing capacity services 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 J.

Capacity revenues are recognized by us for standing ready to deliver electricity to our customers. Our capacity revenues are based on the associated costs we expect to recover in a given year and are generally 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 K.

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 and 2026, our board of directors approved budgets to achieve a 1.10 margins for interest ratio, respectively. 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 unaudited consolidated balance sheets. As of June 30, 2026 and June 30, 2025, we recognized refund liabilities totaling $22,000,000 and $6,250,000, respectively. As of December 31, 2025, we recognized refund liabilities totaling $70,632,000. Based on our current agreements with non-members, we do not refund any consideration received from non-members.

Sales to members for the three and six months ended June 30, 2026 and 2025 were as follows:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	(dollars in thousands)			
	2026	2025	**2026**	2025
Capacity revenues	**$ 395,398**	$ 422,959	**$ 817,639**	$ 836,296
Energy revenues	**178,759**	178,731	**463,519**	433,695
Total	**$ 574,157**	$ 601,690	**$ 1,281,158**	$ 1,269,991

Receivables from contracts with our members at June 30, 2026 and December 31, 2025 were $221,358,000 and $237,834,000, respectively.

Sales to non-members during the three and six months ended June 30, 2026 and 2025 were as follows:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	(dollars in thousands)			
	2026	2025	**2026**	2025
Energy revenues	**$ 15,313**	$ 32,058	**$ 45,368**	$ 41,333
Total	**$ 15,313**	$ 32,058	**$ 45,368**	$ 41,333

Energy revenues from non-members for the three and six months ended June 30, 2026 and June 30, 2025 were primarily from the sale of the BC Smith Energy Facility deferring members' output into the wholesale market.

Our receivables from non-members at June 30, 2026 and December 31, 2025 were $178,375,000 and $159,225,000, respectively. Our non-member receivables are 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. At June 30, 2026 and December 31, 2025, our receivables from non-members 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 that was recognized in December 2025. 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 the 2024 45U NPTCs. For information regarding regulatory accounting, see Note J.

As of June 30, 2026 and December 31, 2025, we have a long-term receivable of $53,566,000 from the U.S. Government relating to 45U NPTCs for fiscal year 2025 that was recognized in December 2025. This long-term receivable is included in the Deferred charges and other assets - Other line item within our unaudited consolidated balance sheets. 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 J.

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 a 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 Vogtle Units No. 3 and No. 4. During the first quarter of 2022, we began applying billing credits to some of our participating members within this program. In December 2022, collections from our members ended for this rate management program. Under this program, net billing credits to participating members during the six months ended June 30, 2026 and 2025 were $33,259,000 and $48,464,000, 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 unaudited consolidated balance sheets. In conjunction with this program, we applied regulated operations accounting to defer these revenues and related investment income on the funds collected. Amounts deferred under the program are amortized to income when applied to members' bills. The net cumulative amount billed since inception of the program totaled $369,102,000. As of June 30, 2026, our remaining liability to be credited to our members' bills was $75,920,000. For additional information regarding our revenue deferral plan, see Note J.

In March 2026, we began an additional rate management program that allows us to recover future expense on a current basis from our members. Our members made a one-time election to participate in this program which, in general, allows for additional collections over a three-year period with those amounts then applied to billings over the subsequent three-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 Smarr Combined Cycle project. Under this program, amounts billed to participating members during the six months ended June 30, 2026 were $1,600,000. Over the three-year period, we expect to collect $32,200,000 from the participating members under this additional rate management program. 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 will be included in the Short-term investments line item within our unaudited 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. For additional information regarding our additional revenue deferral plan, see Note J.

(G) *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 the three and six months ended June 30, 2026 and 2025 was insignificant.

<u>Finance Leases</u>

Three of our Scherer Unit No. 2 finance leases have lease terms through December 31, 2027, and one lease extends through June 30, 2031. At the end of the leases, we can elect at our sole discretion to:

- Renew the leases for a period of not less than one year and not more than five years at fair market value,
- Purchase the undivided interest at fair market value, or
- Redeliver the undivided interest to the lessors.

For rate-making purposes, we include the actual lease payments for our finance leases in our cost of service. The difference between lease payments and the aggregate of the amortization on the right-of-use asset and the interest on the finance lease obligation is recognized as a regulatory asset. Finance lease amortization is recorded in depreciation and amortization expense.

Operating Leases

Our railcar operating leases have terms that extend through November 30, 2028. At the end of the railcar operating leases, we can renew at terms mutually agreeable by us and the lessors, purchase the assets or return the assets to the lessors. We have additional operating leases including one for office equipment that has a term extending through November 30, 2029 and one for real property at one of our electric generating facilities that has a term extending through February 2042 with one renewal option for a 20 year term.

The exercise of renewal options for our finance and operating leases is at our sole discretion.

As all of our operating leases do not provide an implicit rate, we use an 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 non-lease components for all lease agreements.

Classification	**June 30, 2026**	December 31, 2025
	(dollars in thousands)	
Right-of-use assets—Finance leases		
Right-of-use assets	**$ 302,732**	$ 302,732
Less: Accumulated provision for depreciation	**(291,323)**	(288,688)
Total finance lease assets	**$ 11,409**	$ 14,044
Lease liabilities—Finance leases		
Obligations under finance leases	**$ 15,295**	$ 21,578
Long-term debt and finance leases due within one year	**12,236**	11,595
Total finance lease liabilities	**$ 27,531**	$ 33,173

Classification	**June 30, 2026**	December 31, 2025
	(dollars in thousands)	
Right-of-use assets—Operating leases		
Electric plant in service, net	**$ 6,293**	$ 7,357
Total operating lease assets	**$ 6,293**	$ 7,357
Lease liabilities—Operating leases		
Capitalization—Other	**$ 4,323**	$ 5,284
Other current liabilities	**1,970**	2,073
Total operating lease liabilities	**$ 6,293**	$ 7,357

		Three Months Ended		**Six Months Ended**	
Lease Cost	**Classification**	**June 30, 2026**	June 30, 2025	**June 30, 2026**	June 30, 2025
		(dollars in thousands)			
Finance lease cost:					
Amortization of leased assets	Depreciation and amortization	**$ 3,194**	$ 2,603	**$ 5,798**	$ 5,207
Interest on lease liabilities	Interest expense	**543**	1,134	**1,677**	2,268
Operating lease cost:	Inventory[1] & production expense	**613**	592	**1,301**	1,233
Total leased		**$ 4,350**	$ 4,329	**$ 8,776**	$ 8,708

[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.

	June 30, 2026	December 31, 2025
Lease Term and Discount Rate:		
Weighted-average remaining lease term (in years)		
Finance leases	**3.21**	3.55
Operating leases	**4.05**	4.36
Weighted-average discount rate:		
Finance leases	**11.05 %**	11.05 %
Operating leases	**6.12 %**	6.14 %

	Six Months Ended June 30,	
	2026	2025
	(dollars in thousands)	
Other Information:		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance leases	**$ 1,833**	$ 2,408
Operating cash flows from operating leases	**$ 1,301**	$ 1,233
Financing cash flows from finance leases	**$ 5,642**	$ 5,067
Right-of-use assets obtained in exchange for new operating lease liabilities	**$ —**	$ 13

Maturity analysis of our finance and operating lease liabilities as of June 30, 2026 is as follows:

	(dollars in thousands)		
Year Ending December 31,	**Finance Leases**	**Operating Leases**	**Total**
2026	$ 7,475	$ 1,170	$ 8,645
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	1,527	649	2,176
Total lease payments	$ 33,107	$ 7,121	$ 40,228
Less: imputed interest	(5,576)	(828)	(6,404)
Present value of lease liabilities	$ 27,531	$ 6,293	$ 33,824

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 the three and six months ended June 30, 2026 and 2025 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	**2026**	2025
	(dollars in thousands)			
Lease income	**$ 1,571**	$ 1,312	**$ 3,106**	$ 2,596

(H) *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 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.

(I) *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 unaudited consolidated balance sheets that sum to the total of the same such amounts reported in the unaudited consolidated statements of cash flows.

Classification

	Six Months Ended	
	June 30, 2026	June 30, 2025
	(dollars in thousands)	
Cash and cash equivalents	**$ 121,592**	$ 263,052
Restricted cash included in restricted cash and short-term investments	**500**	1,640
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	**$ 122,092**	$ 264,692

(J) *Regulatory Assets and Liabilities.* We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery through future rates. We expect to recover such costs from our members in future revenues through rates under the wholesale power contracts we have with each of our members. The wholesale power 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 our members.

The following regulatory assets and liabilities are reflected on the consolidated balance sheets as of June 30, 2026 and December 31, 2025.

(dollars in thousands)	**2026**	2025
Regulatory Assets:		
Premium and loss on reacquired debt(a)	**$ 26,416**	$ 20,173
Amortization on financing leases(b)	**16,393**	19,556
Outage costs(c)	**59,834**	46,781
Asset retirement obligations – Ashpond and other(l)	**219,511**	228,400
Depreciation expense - Plant Vogtle(d)	**30,567**	31,279
Depreciation expense - Plant Wansley(e)	**305,570**	316,106
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs(f)	**53,157**	53,619
Interest rate options cost(g)	**120,247**	123,650
Deferral of effects on net margin – TA Smith Energy Facility(h)	**115,923**	118,896
Deferral of effects on net margin – BC Smith Energy Facility(p)	**9,925**	13,868
Inventory adjustments - TA Smith Energy Facility(q)	**13,191**	13,701
Accumulated retirement costs for other obligations(i)	**19,305**	5,479
Natural gas hedges(n)	**15,176**	—
Other regulatory assets(o)	**31,916**	32,351
Total Regulatory Assets	**$1,037,131**	$1,023,859
Regulatory Liabilities:		
Deferral of effects on net margin – Hawk Road Energy Facility(h)	**14,480**	14,788
Major maintenance reserve(j)	**132,304**	109,028
Deferred debt service adder(k)	**197,794**	201,836
Asset retirement obligations – Nuclear(l)	**328,857**	245,133
Revenue deferral plan(m)	**75,920**	107,784
Other revenue deferral plan(s)	**1,595**	—
Natural gas hedges(n)	**—**	10,642
Deferral of direct pay nuclear production tax credits(r)	**180,082**	180,082
Other regulatory liabilities(o)	**155**	567
Total Regulatory Liabilities	**$ 931,187**	$ 869,860
Net Regulatory Assets	**$ 105,944**	$ 153,999

(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 Units No. 1 and No. 2, 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 units.

(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 commenced with the commercial operation date of each unit and is being amortized to expense over the life of the units.

(g) Deferral of premiums paid to purchase interest rate options used to hedge interest rates on certain borrowings, related carrying costs and other incidentals associated with construction of Vogtle Units No. 3 and No. 4. Amortization commenced in August 2023 after Vogtle Unit No. 3 was placed in service.

(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 made through 2025 which were in excess of amounts collected through depreciation expense; the deferred credits will be amortized over the remaining useful life of the plants. Amortization commenced in January 2026.

(l) Represents the difference in the timing of recognition of decommissioning costs for financial statement purposes versus rate making purposes, as well as the deferral of unrealized gains and losses of funds set aside for decommissioning.

(m) Deferred revenues under a rate management program that allowed for additional collections over a five-year period which began in 2018. These amounts are being amortized to income and applied to member billings, per each members' election, over the subsequent five-year period.

(n) Represents the deferral of unrealized gains or losses 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.

(s) Deferred revenues under an additional rate management program that allows for additional collections over a three-year period which began in March 2026. These amounts will be amortized to income and applied to member billings, per each members' election, over the subsequent three-year period.

(K) *Member Power Bill Prepayments.* We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. 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.

(L) *Debt.*

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 June 30, 2026, we have repaid $784,850,000 of principal on the notes related to these borrowings and the aggregate Department of Energy-guaranteed borrowings outstanding, including capitalized interest, totaled $3,848,178,000. The final maturity date is February 20, 2044.

b) Rural Utilities Service Guaranteed Loans:

For the six-month period ended June 30, 2026, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $95,655,000 for long-term financing of general and environmental improvements at existing plants and $80,058,000, in April 2026, for our acquisition of the Walton County Power Plant. In conjunction with the loan proceeds received for the acquisition of the Walton County Power Plant, we reclassified, as of March 31, 2026, $73,751,000 of commercial paper to long-term debt and subsequently repaid the corresponding amount of commercial paper in April 2026.

In July 2026, we received $91,707,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

c) Rural Utilities Service Empowering Rural America (New ERA) Loan:

In December 2024, the Rural Utilities Service announced an award to us of a zero-interest loan of up to $331,500,000 under its Empowering Rural America (New ERA) program established under the Inflation Reduction Act of 2022. On May 12, 2026, we and the Rural Utilities Service closed on this loan. We are obligated to use the loan proceeds to refinance an amount of debt approximately equal to the regulatory assets we established in connection with the retirement of the Wansley coal plant. On June 29, 2026, we issued commercial paper to redeem $297,800,000 of outstanding taxable bonds and to pay approximately $4,381,000 of prepayment premium related to the redemption. The redemption amount was approximately equal to the regulatory assets we established in connection with the retirement of the Wansley coal plant. On July 8, 2026, we received $302,181,000 in loan proceeds from the Rural Utilities Service that we used to repay on July 9, 2026 the commercial paper that had been issued to refinance the existing debt. This refinancing resulted in interest expense savings that we will pass on to our members. In connection with our receipt of the loan proceeds, we reclassified, approximately $302,181,000 of commercial paper to long-term debt as of June 30, 2026.

d) CFC Term Loan:

On August 10, 2026, we received $40,850,000 in loan proceeds from CFC that we used to repay on August 10, 2026 the commercial paper that had been issued to finance operating costs for four of our electric generating facilities that were deferred or are currently being deferred by our members. In connection with our receipt of the CFC term loan proceeds, we reclassified, approximately $39,125,000 of commercial paper to long-term debt as of June 30, 2026.

e) Credit Facilities:

As of June 30, 2026, 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 June 30, 2026, our credit facilities permit the issuance of up to $810,000,000 in letters of credit in the aggregate, of which $505,000,000 remained available. At June 30, 2026, we had (i) $2,504,000 under these lines of credit in the form of issued letters of credit and (ii) $1,077,352,000 dedicated under one of these lines of credit to support a like face value of commercial paper that was outstanding.

(M) *Measurement of Credit Losses on Financial Instruments.* The financial assets we hold that are subject to credit losses (Topic 326) are predominately to 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 F 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.

(N) *Asset Retirement Obligations.* During the six months ended June 30, 2026, no change in cash flow estimates related to nuclear or coal ash related asset retirement obligations was recorded. We expect to receive more refined estimates from Georgia Power regarding closure costs and the timing of coal ash expenditures in the fourth quarter of 2026. Prior period's amount for settlement of asset retirement obligations has been reclassified to conform with current year presentation within our unaudited consolidated statement of cash flows. Settlement of asset retirement obligations were previously included in the Other current liabilities line item of our unaudited consolidated statement of cash flows.

(O) *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. As of June 30, 2026, we had incurred costs of approximately $662.0 million with respect to this project. For additional information regarding this project, see Note 14 in our 2025 Form 10-K.

(P) *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. Our current budget for this project, which includes capital costs, allowance for funds used during construction and a contingency amount, is approximately $440 million. The projected commercial operation date for this unit is 2029. As of June 30, 2026, we had incurred costs of approximately $68.5 million with respect to this project. For additional information regarding this project, see Note 15 in our 2025 Form 10-K.

(Q) *Spent Nuclear Fuel Storage Costs.* 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.

On September 5, 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 June 30, 2026 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.

For additional information regarding nuclear fuel costs, see Note 1g in our 2025 Form 10-K.

(R) *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 in our 2025 Form 10-K.

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.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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 members are consumer-owned distribution cooperatives providing retail electric service in Georgia on a not-for-profit basis. Our principal business is providing wholesale electric power to our members, which we provide primarily from our generation assets and, to a lesser extent, from power purchased from other suppliers. As with cooperatives generally, we operate on a not-for-profit basis.

We have a substantially similar wholesale power contract with each member that extends to December 31, 2085, and each contract will continue thereafter until terminated by three years' written notice by us or the respective member. For additional information regarding our wholesale power contracts with our members, see "Item 1–BUSINESS–OGLETHORPE POWER CORPORATION–Wholesale Power Contracts" in our 2025 Form 10-K.

Results of Operations

For the Three and Six Months Ended June 30, 2026 and 2025

Net Margin

Our net margin for the three-month and six-month periods ended June 30, 2026 were $16.2 million and $64.4 million, respectively, compared to $20.3 million and $63.3 million, respectively, for the same periods of 2025. Through June 30, 2026, we collected approximately 115% of our targeted net margin of $55.8 million for the year ending December 31, 2026. These collections are typical as our capacity revenues are generally recorded evenly throughout the year. We anticipate our board of directors will approve a budget adjustment by year end so that margins will achieve, but not exceed, the 2026 targeted margins for interest ratio of 1.10. As a result, we assessed our projected margin and annual revenue requirement to meet the targeted margins for interest ratio to determine if a refund liability should be recognized. As a result of this assessment, we recognized cumulative refund liabilities of $22.0 million and $6.3 million as of June 30, 2026 and June 30, 2025, respectively. For additional information regarding our net margin requirements and policy, see "Item 7–MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Summary of Cooperative Operations—*Margins*" in our 2025 Form 10-K.

Operating Revenues

Our operating 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, operating costs, availability of electric generation resources, our decisions of whether to dispatch our owned, purchased or member-owned resources over which we have dispatch rights and our members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers, and sales to non-members.

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 for the three-month and six-month periods ended June 30, 2026 and 2025 were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	(dollars in thousands)					
	2026	2025	% Change	**2026**	2025	% Change
Capacity revenues	**$ 395,398**	$ 422,959	(6.5)%	**$ 817,639**	$ 836,296	(2.2)%
Energy revenues	**178,759**	178,731	— %	**463,519**	433,695	6.9 %
Total	**$ 574,157**	$ 601,690	(4.6)%	**$1,281,158**	$1,269,991	0.9 %
MWh Sales to members[1]	**8,388,348**	8,086,872	3.7 %	**15,380,268**	15,504,762	(0.8)%
Cents/kWh	**6.84**	7.44	(8.0)%	**8.33**	8.19	1.7 %
Member energy requirements supplied	**75 %**	74 %	1.4 %	**69 %**	70 %	(1.4)%

[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.

Energy revenues from members increased for the six-month period ended June 30, 2026 compared to the same period in 2025, primarily due to the recovery of higher fuel costs offset by a decrease in megawatt-hours sold to members. Energy revenues from members was relatively unchanged for the three-month period ended June 30, 2026 compared to the same period in 2025. For a discussion of fuel costs, which are the primary costs recovered by energy revenues, see "—*Operating Expenses*." Capacity revenues from members decreased slightly for the six-month period ended June 30, 2026 compared to the same period in 2025. Capacity revenues from members decreased for the three-month period ended June 30, 2026 compared to the same period in 2025 primarily due to the increase in refund liability recognized during the second quarter in 2026 compared to the same period in 2025.

Sales to non-members. Sales to non-members during the three-month and six-month periods ended June 30, 2026 and 2025 were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
			(dollars in thousands)			
	2026	2025	% Change	**2026**	2025	% Change
Energy revenues	**15,313**	32,058	(52.2)%	**45,368**	41,333	9.8 %
Total	**$ 15,313**	$ 32,058	(52.2)%	**$ 45,368**	$ 41,333	9.8 %
MWh Sales to non-members	**347,057**	751,313	(53.8)%	**566,716**	928,044	(38.9)%
Cents/kWh	**4.41**	4.27	3.3 %	**8.01**	4.45	80.0 %

Energy revenues from non-members were primarily from the sale of the BC Smith Energy Facility's deferring members' output into the wholesale market. Energy revenues from non-members decreased for the three-month period ended June 30, 2026 compared to the same period in 2025 primarily due to a decrease in megawatt-hours sold to non-members and recovery of lower fuel costs. Energy revenues from non-members increased for the six-month period ended June 30, 2026 compared to the same period in 2025 primarily due to recovery of higher fuel costs offset by a decrease in megawatt-hours sold to non-members.

Operating Expenses

Fuel

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

	Cost (dollars in thousands)			Generation[1] (MWh)			Cents per kWh		
	Three Months Ended June 30,			Three Months Ended June 30,			Three Months Ended June 30,		
Fuel Source	**2026**	2025	% Change	**2026**	2025	% Change	**2026**	2025	% Change
Coal	**$ 26,822**	$ 34,923	(23.2)%	**689,435**	799,502	(13.8)%	**3.89**	4.37	(11.0)%
Nuclear	**27,770**	29,954	(7.3)%	**3,789,758**	3,780,694	0.2%	**0.73**	0.79	(7.6)%
Gas:[2]									
Combined Cycle	**89,480**	90,914	(1.6)%	**3,746,968**	3,731,235	0.4%	**2.39**	2.44	(2.0)%
Combustion Turbine	**29,202**	31,047	(5.9)%	**781,162**	775,755	0.7%	**3.74**	4.00	(6.5)%
	$173,274	$186,838	(7.3)%	**9,007,323**	9,087,186	(0.9)%	**1.92**	2.06	(6.8)%

	Cost (dollars in thousands)			Generation[1] (MWh)			Cents per kWh		
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,		
Fuel Source	**2026**	2025	% Change	**2026**	2025	% Change	**2026**	2025	% Change
Coal	**$ 58,163**	$ 78,336	(25.8)%	**1,510,838**	1,997,285	(24.4)%	**3.85**	3.92	(1.8)%
Nuclear	**52,688**	57,572	(8.5)%	**7,220,197**	7,300,135	(1.1)%	**0.73**	0.79	(7.6)%
Gas:[2]									
Combined Cycle	**289,872**	248,108	16.8%	**6,739,064**	6,701,097	0.6%	**4.30**	3.70	16.2%
Combustion Turbine	**57,942**	45,469	27.4%	**969,307**	880,025	10.1%	**5.98**	5.17	15.7%
	$458,665	$429,485	6.8%	**16,439,406**	16,878,542	(2.6)%	**2.79**	2.54	9.8%

[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] Realized gains and losses on natural gas swaps are included in fuel expense.

Total fuel costs increased for the six-month period ended June 30, 2026 compared to the same period in 2025 as a result of an increase in the average cost of fuel offset by a decrease in generation for members. The increase in average fuel cost was primarily driven by significantly elevated natural gas prices during winter storm events from mid-January 2026 through mid-February 2026. The decrease in generation was primarily attributable to lower output from our coal-fired generating units compared to the same period in 2025, reflecting reduced dispatch during the six-month period ended June 30, 2026 compared to the same period in 2025 when natural gas costs were comparatively lower except during the winter storm events period. Total fuel costs decreased for the three-month period ended June 30, 2026 compared to the same period in 2025 primarily as a result of a decrease in generation for members and a decrease in the average cost of fuel. The decrease in generation was primarily attributable to lower output from our coal-fired generating units compared to the same period in 2025, reflecting reduced dispatch during the three-month period ended June 30, 2026 compared to the same period in 2025 when natural gas costs were comparatively lower.

Production Expenses
Production costs decreased for three-month and six-month periods ended June 30, 2026 as compared to the same periods in 2025 primarily as a result of lower fixed major maintenance outage costs associated with our natural gas-fired facilities offset by the deferral of net margins associated with BC Smith. Production costs can vary due to the number and extent of maintenance outages in a given year.

Depreciation and Amortization
Depreciation and amortization increased slightly for the three-month and six-month periods ended June 30, 2026 as compared to the same periods in 2025.

Interest Charges
Net interest charges remained relatively unchanged for the three-month and six-month periods ended June 30, 2026 as compared to the same periods in 2025. The allowance for debt funds used during construction increased for the three-month and six-month periods ended June 30, 2026 primarily due to capitalization of interest related to construction of Smarr Combined Cycle project as compared to the same periods in 2025.

Financial Condition

Balance Sheet Analysis as of June 30, 2026

Assets

Cash used for property additions for the six-month period ended June 30, 2026 totaled $623.7 million. Of this amount, $490.4 million related to construction work in progress during the six-month period ended June 30, 2026, primarily due to construction at our two new natural gas-fired generation resources as well as additions and replacements at our existing electric generating facilities. An additional $63.1 million was for nuclear fuel purchases.

The increase in the nuclear decommissioning trust fund was primarily due to the increase in the fair market value of investments due to continued appreciation in the stock market during the six-month period ended June 30, 2026.

Long-term investments decreased $6.9 million for the six-month period ended June 30, 2026, primarily due to a $39.1 million redemption of coal ash investments to fund settlement of asset retirement obligations, $33.3 million redeemed to fund expenses 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 redemption of $18.1 million to fund major maintenance outages expenses. Offsetting these decreases was a $83.6 million increase in funds invested, including reinvestment of earnings. See Notes F and J of Notes to Unaudited Consolidated Financial Statements for a discussion of our member rate management programs and regulatory liabilities.

Inventories increased $35.4 million during the six-month period ended June 30, 2026 primarily due to an increase of $26.2 million in material and supplies at our electric generating facilities and an increase in fuel inventories of $9.2 million due to decreased generation at our coal-fired units and the associated decrease in coal burn.

Regulatory assets increased $13.3 million largely as a result of a $15.2 million increase in our asset associated with unrealized losses on our natural gas contracts and a $13.8 million increase in our deferral of retirement costs associated with long-lived assets for which there are no legal obligations to retire the assets. Offsetting these increases was a $10.5 million decrease in our regulatory asset for the accelerated depreciation associated with the early retirement of Plant Wansley, which occurred in 2022, and an $8.9 million decrease in the deferral associated with coal ash pond asset retirement obligations.

Equity and Liabilities

Long-term debt and long-term debt and finance leases due within one year increased $26.5 million for the six-month period ended June 30, 2026 and was primarily the result of reclassification of $302.2 million of commercial paper to long-term debt that was refinanced through proceeds under Rural Utilities Service's Empowering Rural America (New ERA) loan program in July 2026, $175.7 million in advances under Rural Utilities Service-guaranteed loans and the reclassification of $39.1 million of commercial paper to long-term debt that was refinanced through proceeds under the CFC term loan in August 2026. Offsetting these increases was $497.6 million in debt service payments. See Note L of Notes to Unaudited Consolidated Financial Statements for additional information regarding long-term debt.

Short-term borrowings, which primarily provide interim financing for the new Smarr Combined Cycle and Talbot Unit No. 7 projects and the deferral of effects on net margin for Washington County Power Plant, BC Smith, Walton County and Baconton, increased $273.3 million during the six-month period ended June 30, 2026. This increase was primarily as a result of borrowings of $722.5 million, offset by the reclassification of $302.2 million of commercial paper to long-term debt that was refinanced through proceeds under the Rural Utilities Service's New ERA loan program in July 2026, repayments of $107.9 million and the reclassification of $39.1 million of commercial paper to long-term debt that was refinanced through proceeds under the CFC term loan in August 2026 for commercial paper that had been issued to finance operating costs for four of our electric generating facilities that were deferred or are currently being deferred by our members.

Accounts payable decreased $118.3 million during the six-month period ended June 30, 2026, primarily due to applying $70.6 million in credits to our members' bills in the first quarter of 2026 for a board-approved reduction in 2025 revenue in excess of the requirement to meet the 2025 targeted net margin, a $50.2 million decrease in Georgia Power payables and a $27.1 million decrease in trade payables offset by a $22.0 million refund liability recognized during the second quarter of 2026.

Other current liabilities decreased $12.7 million for the six-month period ended June 30, 2026, primarily as a result of a $27.3 million decrease in accrued property taxes offset by a $14.6 million increase in accrued liabilities principally for property additions for our new generation projects.

Regulatory liabilities increased $61.3 million for the six-month period ended June 30, 2026 primarily due to an $83.7 million increase in deferred nuclear asset retirement obligations that was primarily driven by an increase in unrealized gains associated with our nuclear decommissioning investments and a net $23.3 million increase in the liability for collections of future major maintenance outage costs. Offsetting these increases, was a $31.9 million decrease in the liability for our revenue deferral rate management plan, which is associated with the Vogtle Units No. 3 and No. 4, and a $10.6 million decrease in the liability associated with unrealized gains on our natural gas contracts. See Notes F and J of Notes to Unaudited Consolidated Financial Statements for a discussion of our member rate management programs and regulatory liabilities.

Capital Requirements and Liquidity and Sources of Capital

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. As of June 30, 2026, we had incurred costs of approximately $662.0 million with respect to this project. For additional information regarding this project, see Note 14 in our 2025 Form 10-K.

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. Our current budget for this project, which includes capital costs, allowance for funds used during construction and a contingency amount, is approximately $440 million. The projected commercial operation date for this unit is 2029. As of June 30, 2026, we had incurred costs of approximately $68.5 million with respect to this project. For additional information regarding this project, see Note 15 in our 2025 Form 10-K.

We intend to finance the Smarr and Talbot projects on an intermediate-term basis through our commercial paper program as well as through intermediate-term capital markets debt issuances or bank financings. We are pursuing Rural Utilities Service financing as our primary source of long-term financing for the Smarr Combined Cycle and Talbot Unit No. 7 projects, subject to program availability, and we expect to issue first mortgage bonds for any costs not financed by the Rural Utilities Service.

Additional Approved Resources

We and our members have also approved the development and construction of several additional projects. One project 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. A second project is to modify one of our existing natural gas 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 2032. We and our members are also proceeding with over 100 megawatts of capacity upgrades to some of our existing generation resources that will be phased in through 2031 and have an aggregate budget of approximately $200 million.

We and our members may also consider additional generation and capacity upgrades beyond these resources in the future. See “RISK FACTORS” for a discussion of certain risks associated with these new generation projects in our 2025 Form 10-K.

Plant Hatch

On June 12, 2026, the Nuclear Regulatory Commission approved Southern Nuclear Operating Company, Inc.'s subsequent license renewal application for Plant Hatch Units No. 1 and No. 2, renewing both units' operating licenses for an additional 20 years (through years 2054 and 2058 for Units No. 1 and No. 2, respectively).

Environmental Regulations

Federal and state laws and regulations regarding environmental matters affect operations at our facilities. For a discussion regarding potential effects on our business from environmental regulations, including potential capital requirements, see "Item 1—BUSINESS—REGULATION—Environmental," "Item 1A—RISK FACTORS" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements*—*Capital Expenditures*" in our 2025 Form 10-K.

In 2015, EPA established a comprehensive regulatory program to manage the disposal of coal combustion residuals (CCR) from coal-fired power plants as non-hazardous material under the Resource Conservation and Recovery Act (RCRA). The 2015 CCR rule sets forth requirements for structural integrity assessments, groundwater monitoring, location siting, composite lining, inactive units, closure and post closure, beneficial use recycling, design and operating criteria, recordkeeping, notification, and internet posting for new and existing CCR landfills, CCR surface impoundments and lateral expansions of CCR disposal facilities. Since 2015, EPA has made subsequent revisions to CCR requirements and, beginning in 2022, EPA issued a number of proposed and final determinations on requests for extensions of time to close ash ponds, which could affect the Georgia Environmental Protection Division's (EPD) review of the proposed closure plans for the coal ash ponds at Plants Wansley and Scherer. In May 2024, EPA adopted new CCR regulations that expanded regulatory requirements to cover Legacy Surface Impoundments and CCR Management Units that were previously exempt. Certain compliance deadlines related to CCR management units were then extended in February 2026. On April 13, 2026, EPA proposed to amend the 2024 CCR regulations by modifying certain legacy surface impoundment and CCR management unit provisions; establishing compliance pathways that allow for site-specific considerations for closure requirements, among other things; and adopting new provision for beneficial use. 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.

Liquidity

At June 30, 2026, we had $767 million of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $122 million in cash and cash equivalents and $645 million available under our $1.7 billion of committed credit arrangements, the details of which are reflected in the table below:

Committed Credit Facilities

	Authorized Amount	Available June 30, 2026	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line among 11 banks led by CFC (1)	$ 1,275	$ 198	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 the face value of outstanding commercial paper at June 30, 2026.

(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 June 30, 2026, $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 $1.3 billion syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up commercial paper.

Under our commercial paper program, we are authorized to issue commercial paper in amounts that do not exceed the amount of our committed backup lines of credit, thereby providing 100% dedicated support for any commercial paper outstanding. Due to this requirement, any commercial paper we issue will reduce the availability under the $1.3 billion syndicated line of credit. At June 30, 2026, our $1.1 billion of outstanding commercial paper was primarily used to provide interim funding for:

- costs related to the new Smarr Combined Cycle and Talbot Unit No. 7 projects,
- the interim refinancing of first mortgage bonds in an amount approximately equal to the regulatory assets established in connection with the retirement of Plant Wansley, pending receipt of proceeds from the Rural Utilities Service's zero-interest New ERA loan,
- costs related to capital expenditures for existing generating facilities, 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.

In July 2026, we received $302.2 million of long-term financing through the Rural Utilities Service's zero-interest New ERA loan to refinance debt approximately equal to the regulatory assets established in connection with the retirement of Plant Wansley, the proceeds of which were used to repay the related commercial paper borrowings. In August 2026, we borrowed $41 million under the CFC Term Loan facility, to provide long-term financing for a portion of the net costs, after off-system sales revenues, associated with recently acquired generation facilities that were incurred prior to recovery through member rates. We used the proceeds from this loan advance to repay the related commercial paper borrowings.

We are pursuing Rural Utilities Service financing as our primary source of long-term financing for the Smarr Combined Cycle and Talbot Unit No. 7 projects as well as for capital expenditures for existing generating facilities, subject to program availability. 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. We intend to use long-term bank financing secured under our first mortgage indenture for the remaining net costs associated with recently acquired generation facilities that are incurred prior to recovery through member rates. We intend to seek intermediate-term financing through new unsecured bank loans and through first mortgage bond issuances in the capital markets to fund, prior to arranging long-term financing, a portion of the costs of the Smarr Combined Cycle and Talbot Unit No. 7 projects, and for capital expenditures on existing generating facilities.

Our unsecured committed lines of credit permit the issuance of up to $810 million in letters of credit on our behalf, of which $505 million remained available at June 30, 2026. This letter of credit issuance capacity includes up to $500 million under our $1.3 billion syndicated line of credit, $200 million under our JPMorgan Chase line of credit, and $110 million under our CFC line of credit. Between projected cash on hand and the credit arrangements currently in place, we believe we have sufficient liquidity to cover normal operations and our interim financing needs, including interim financing for the new natural gas resources, until intermediate or 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 June 30, 2026, 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 June 30, 2026, we had $1.1 billion 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 June 30, 2026, we had five members participating in the program and a balance of $58.8 million remaining to be applied against future power bills.

Financing Activities

First Mortgage Indenture. At June 30, 2026, we had $12.6 billion of long-term debt outstanding, consisting of $12.2 billion under our first mortgage indenture secured equally and ratably by a lien on substantially all of our owned tangible and certain of our intangible property, including property we acquire in the future, $0.3 billion of commercial paper that we reclassified to long-term debt in connection with our receipt of New ERA loan proceeds from the Rural Utilities Service on July 8, 2026 and $39.1 million of commercial paper that we reclassified to long-term debt in connection with our receipt of CFC term loan proceeds on August 10, 2026. On July 8, 2026, our long-term debt outstanding balance, under our first mortgage indenture increased from $12.2 billion to $12.5 billion due to our $0.3 billion advance under the Rural Utilities Service's New ERA loan.

See "Item 1—BUSINESS—OGLETHORPE POWER CORPORATION—First Mortgage Indenture" in our 2025 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. A summary of our current Rural Utilities Service-Guaranteed Loans as of June 30, 2026 is provided in the table below:

Current Rural Utilities Service-Guaranteed Loans			
	Amount Approved	Amount Advanced June 30, 2026	Amount Remaining June 30, 2026
	(dollars in millions)		
General and Environmental Improvements[1, 2]	$ 630.3	$ 510.3	$ 120.0
General and Environmental Improvements[3, 4]	755.2	408.8	346.4
General and Environmental Improvements[5]	112.6	—	112.6
Walton Acquisition	80.1	80.1	—
New ERA Wansley Debt Refinancing[6]	331.5	—	331.5
Total	$ 1,909.7	$ 999.2	$ 910.5

(1) We are able to advance under this loan through September 30, 2026.
(2) We advanced an additional $32.9 million available under this loan in July 2026.
(3) We are able to advance under this loan through May 30, 2028.
(4) We advanced an additional $58.8 million available under this loan in July 2026.
(5) This loan was conditionally approved by the Rural Utilities Service in February 2026 and we expect to close and advance on this loan in 2027.
(6) The New ERA loan is a direct loan from the Rural Utilities Service. We advanced $302.2 million available under this loan in July 2026.

As of June 30, 2026, we had $2.9 billion of debt outstanding under various Rural Utilities Service-guaranteed loans.

Subsequent to June 30, 2026, the Rural Utilities Service conditionally approved two additional loans. In July 2026, the Rural Utilities Service conditionally approved a Rural Utilities Service-guaranteed loan for general and environmental improvements in the amount of $486.7 million that we expect to close on and advance by 2027. On August 6, 2026, the Rural Utilities Service conditionally approved a $3,324.3 million loan for our Smarr Combined Cycle project that we expect to close on and advance by 2028. The Smarr Combined Cycle loan is divided into a $1,861 million Rural Utilities Service direct loan and a $1,463 million Rural Utilities Service-guaranteed loan. We have also applied for an additional $415 million Rural Utilities Service-guaranteed loan to provide for long-term financing for our Talbot Unit No. 7 project. 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.

In December 2024, the Rural Utilities Service announced an award to us of a zero-interest loan of up to $331.5 million under its Empowering Rural America (New ERA) program established under the Inflation Reduction Act of 2022. On May 12, 2026, we and the Rural Utilities Service closed on this loan. We are obligated to use the loan proceeds to refinance an amount of debt approximately equal to the regulatory assets we established in connection with the retirement of the Wansley coal plant. On June 29, 2026, we issued commercial paper to redeem $297.8 million of outstanding taxable bonds and to pay approximately $4.4 million of prepayment premium related to the redemption. The redemption amount was approximately equal to the regulatory assets we established in connection with the retirement of the Wansley coal plant. On July 8, 2026, we received $302.2 million in loan proceeds from the Rural Utilities Service that we used to repay on July 9, 2026 the commercial paper that had been issued to refinance the existing debt. This refinancing resulted in interest expense savings that we will pass on to our members. In connection with our receipt of the loan proceeds, we reclassified, approximately $302.2 million of commercial paper to long-term debt as of June 30, 2026.

All of the amounts outstanding under Rural Utilities Service-guaranteed or direct loans are secured ratably with all other debt under our first mortgage indenture.

For more detailed information regarding our financing plans, see "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities*" in our 2025 Form 10-K.

Newly Adopted or Issued Accounting Standards

For a discussion of recently issued or adopted accounting pronouncements, see Note E of Notes to Unaudited Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes to the market risks disclosed in "Item 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK" in our 2025 Form 10-K.

Item 4. Controls and Procedures

As of June 30, 2026, 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 the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

There have been no changes in internal control over financial reporting or other factors that occurred during the quarter ended June 30, 2026 that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

See Note H to Unaudited Consolidated Financial Statements.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in "Item 1A—Risk Factors" in our 2025 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not Applicable.

Item 3. Defaults upon Senior Securities

Not Applicable.

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

During the fiscal quarter ended June 30, 2026, 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 quarterly report on Form 10-Q, we are a membership corporation and have no authorized or outstanding equity securities although we do have outstanding debt securities.

Item 6. Exhibits

Number	Description
4.1	Fifteenth Amended and Restated Loan Contract, dated as of May 12, 2026, between Oglethorpe and the United States of America.
4.2	Ninety-Fourth Supplemental Indenture, dated as of May 12, 2026, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to the Series 2026 (AL440 RUS New ERA) Reimbursement Note.
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Annalisa M. Bloodworth (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Annalisa M. Bloodworth (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).
101	XBRL Interactive Data File.
104	Cover Page Interactive Data File, formatted in Inline XBRL.

SIGNATURES

Pursuant to the requirements 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.

		Oglethorpe Power Corporation (An Electric Membership Corporation)
Date: August 13, 2026	By:	/s/ Annalisa M. Bloodworth
		Annalisa M. Bloodworth President and Chief Executive Officer
Date: August 13, 2026		/s/ Elizabeth B. Higgins
		Elizabeth B. Higgins Executive Vice President and Chief Financial Officer (Principal Financial Officer)