
**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, 2013

OR

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

For the transition period from _____ to _____

Commission File No. 000-53908



OglethorpePowerCorporation

(An Electric Membership Corporation)

(Exact name of registrant as specified in its charter)

Georgia

(State or other jurisdiction of
incorporation or organization)

58-1211925

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

2100 East Exchange Place

Tucker, Georgia

(Address of principal executive offices)

30084-5336

(Zip Code)

Registrant's telephone number, including area code

(770) 270-7600

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one): **Large Accelerated Filer** ☐ **Accelerated Filer** ☐ **Non-Accelerated Filer** ☒ (Do not check if a smaller reporting company) **Smaller Reporting Company** ☐

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

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.**

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OGLETHORPE POWER CORPORATION
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FOR THE QUARTER ENDED JUNE 30, 2013

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS AND ASSOCIATED RISKS

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 the timing of various regulatory and other actions, future capital expenditures, business strategy and development, construction or operation of facilities (often, but not always, identified through the use of words or phrases such as “will likely result,” “are expected to,” “will continue,” “is anticipated,” “estimated,” “projection,” “target” and “outlook”) are forward-looking statements.

Although we believe that in making these forward-looking statements our expectations are based on reasonable assumptions, any forward-looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward-looking statements. Some of the risks, uncertainties and assumptions that may cause actual results to differ from these forward-looking statements are described under the heading “RISK FACTORS” and in other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012. 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 construction projects, including the construction of two additional nuclear units at Plant Vogtle;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- potential legislative and regulatory responses to climate change initiatives, including the regulation of carbon dioxide and other greenhouse gas emissions;
- increasing debt caused by significant capital expenditures which is weakening certain of our financial metrics;
- commercial banking and financial market conditions;
- our access to capital, the cost to access capital, and the results of our financing and refinancing efforts, including availability of funds in the capital markets;
- uncertainty as to the continued availability of funding from the Rural Utilities Service and the availability of funding from the U.S. Department of Energy and other government sources;
- actions by credit rating agencies;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;

- adequate funding of our nuclear decommissioning trust fund including investment performance and projected decommissioning costs;
- weather conditions and other natural phenomena;
- continued efficient operation of our generation facilities by us and third-parties;
- the availability of an adequate and economical supply of fuel, water and other materials;
- reliance on third-parties to efficiently manage, distribute and deliver generated electricity;
- acts of sabotage, wars or terrorist activities, including cyber attacks;
- the credit quality and/or inability of various counterparties to meet their financial obligations to us, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- changes in technology available to and utilized by us or our competitors;
- general economic conditions;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption, energy conservation efforts and the general economy;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- litigation or legal and administrative proceedings and settlements;
- significant changes in critical accounting policies material to us; and
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation

Condensed Balance Sheets (Unaudited)

June 30, 2013 and December 31, 2012

	(dollars in thousands)	
	2013	2012
Assets		
Electric plant:		
In service	\$ 7,678,439	\$ 7,506,707
Less: Accumulated provision for depreciation	(3,541,332)	(3,472,087)
	<u>4,137,107</u>	<u>4,034,620</u>
Nuclear fuel, at amortized cost	314,660	321,196
Construction work in progress	<u>2,329,218</u>	<u>2,240,920</u>
	<u>6,780,985</u>	<u>6,596,736</u>
Investments and funds:		
Nuclear decommissioning trust fund	311,590	300,785
Deposit on Rocky Mountain transactions	14,878	14,392
Investment in associated companies	63,109	60,770
Long-term investments	77,634	77,022
Restricted cash	36,074	8,953
Other	472	1,084
	<u>503,757</u>	<u>463,006</u>
Current assets:		
Cash and cash equivalents	220,650	298,565
Restricted short-term investments	206,211	64,671
Receivables	162,379	134,896
Inventories, at average cost	267,851	263,949
Prepayments and other current assets	17,945	16,073
	<u>875,036</u>	<u>778,154</u>
Deferred charges:		
Deferred debt expense, being amortized	64,738	63,210
Regulatory assets	356,595	352,902
Other	48,410	60,558
	<u>469,743</u>	<u>476,670</u>
	<u>\$ 8,629,521</u>	<u>\$ 8,314,566</u>

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

Oglethorpe Power Corporation
Condensed Balance Sheets (Unaudited)
June 30, 2013 and December 31, 2012

	(dollars in thousands)	
	2013	2012
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	\$ 719,535	\$ 673,009
Accumulated other comprehensive (deficit) margin	(399)	903
	<u>719,136</u>	<u>673,912</u>
Long-term debt	5,770,689	5,784,130
Obligation under capital leases	128,962	135,943
Obligation under Rocky Mountain transactions	14,878	14,392
	<u>6,633,665</u>	<u>6,608,377</u>
Current liabilities:		
Long-term debt and capital leases due within one year	460,615	168,393
Short-term borrowings	538,261	569,480
Accounts payable	78,531	145,451
Accrued interest	89,671	58,649
Accrued and withheld taxes	17,689	4,881
Member power bill prepayments, current	124,090	65,079
Other current liabilities	16,387	19,539
	<u>1,325,244</u>	<u>1,031,472</u>
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	22,898	23,638
Asset retirement obligations	389,301	381,362
Member power bill prepayments, non-current	32,702	40,853
Power sale agreement, being amortized	33,231	40,355
Regulatory liabilities	131,819	129,985
Other	60,661	58,524
	<u>670,612</u>	<u>674,717</u>
	<u>\$8,629,521</u>	<u>\$8,314,566</u>

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

Oglethorpe Power Corporation
Condensed Statements of Revenues and Expenses (Unaudited)
For the Three and Six Months Ended June 30, 2013 and 2012

(dollars in thousands)				
	Three Months		Six Months	
	2013	2012	2013	2012
Operating revenues:				
Sales to Members	\$306,191	\$310,483	\$592,844	\$605,713
Sales to non-Members	18,158	37,220	37,419	61,214
Total operating revenues	324,349	347,703	630,263	666,927
Operating expenses:				
Fuel	113,065	139,188	213,215	248,416
Production	89,294	89,844	184,014	188,343
Depreciation and amortization	38,578	40,556	75,661	85,100
Purchased power	14,717	11,821	27,384	23,936
Accretion	5,677	4,859	11,307	9,716
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	(6,777)	(2,484)	(18,667)	(14,559)
Total operating expenses	254,554	283,784	492,914	540,952
Operating margin	69,795	63,919	137,349	125,975
Other income:				
Investment income	8,148	7,760	15,425	16,015
Other	2,240	3,156	4,517	6,899
Total other income	10,388	10,916	19,942	22,914
Interest charges:				
Interest expense	76,251	78,839	152,028	154,846
Allowance for debt funds used during construction	(24,562)	(20,017)	(49,416)	(40,437)
Amortization of debt discount and expense	3,992	5,135	8,153	10,082
Net interest charges	55,681	63,957	110,765	124,491
Net margin	\$ 24,502	\$ 10,878	\$ 46,526	\$ 24,398

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

Oglethorpe Power Corporation
Condensed Statements of Comprehensive Margin (Unaudited)
For the Three and Six Months Ended June 30, 2013 and 2012

(dollars in thousands)				
	Three Months		Six Months	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
Net margin	<u>\$24,502</u>	<u>\$10,878</u>	<u>\$46,526</u>	<u>\$24,398</u>
Other comprehensive margin:				
Unrealized (loss) gain on available-for-sale securities	<u>(1,090)</u>	<u>120</u>	<u>(1,302)</u>	<u>828</u>
Total comprehensive margin	<u>\$23,412</u>	<u>\$10,998</u>	<u>\$45,224</u>	<u>\$25,226</u>

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

Oglethorpe Power Corporation
Condensed Statements of Patronage Capital and Membership Fees
and Accumulated Other Comprehensive Margin (Deficit) (Unaudited)
For the Six Months Ended June 30, 2013 and 2012

	(dollars in thousands)		
	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Margin (Deficit)	Total
Balance at December 31, 2011	\$633,689	\$ 618	\$634,307
Components of comprehensive margin:			
Net margin	24,398	—	24,398
Unrealized gain on available-for-sale securities	—	828	828
Balance at June 30, 2012	\$658,087	\$ 1,446	\$659,533
Balance at December 31, 2012	\$673,009	\$ 903	\$673,912
Components of comprehensive margin:			
Net margin	46,526	—	46,526
Unrealized loss on available-for-sale securities	—	(1,302)	(1,302)
Balance at June 30, 2013	\$719,535	\$ (399)	\$719,136

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

Oglethorpe Power Corporation
Condensed Statements of Cash Flows (Unaudited)
For the Six Months Ended June 30, 2013 and 2012

	(dollars in thousands)	
	2013	2012
Cash flows from operating activities:		
Net margin	\$ 46,526	\$ 24,398
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	141,876	156,664
Accretion cost	11,307	9,716
Amortization of deferred gains	(893)	(2,830)
Allowance for equity funds used during construction	(1,411)	(1,432)
Deferred outage costs	(31,820)	(13,379)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	(18,667)	(14,559)
Gain on sale of investments	(17,304)	(5,625)
Regulatory deferral of costs associated with nuclear decommissioning	10,085	165
Other	(3,551)	(3,908)
Change in operating assets and liabilities:		
Receivables	(28,158)	(34,699)
Inventories	(3,902)	7,591
Prepayments and other current assets	(1,872)	(2,826)
Accounts payable	(43,540)	(43,758)
Accrued interest	31,022	(7,599)
Accrued taxes	12,808	(4,389)
Other current liabilities	(5,067)	(3,644)
Member power bill prepayments	50,860	(8,331)
Total adjustments	101,773	27,157
Net cash provided by operating activities	148,299	51,555
Cash flows from investing activities:		
Property additions	(321,246)	(346,654)
Activity in decommissioning fund—Purchases	(346,211)	(418,240)
—Proceeds	343,340	415,247
(Increase) decrease in restricted cash	(27,121)	22,378
(Increase) decrease in restricted short-term investments	(141,540)	43,601
Activity in other long-term investments—Purchases	(19,670)	(2,993)
—Proceeds	20,103	10,846
Activity on interest rate options—Collateral returned	(46,420)	(43,070)
—Collateral received	73,540	20,690
Other	1,269	11,707
Net cash used in investing activities	(463,956)	(286,488)
Cash flows from financing activities:		
Long-term debt proceeds	283,168	79,194
Long-term debt payments	(244,042)	(68,678)
Increase in short-term borrowings, net	201,391	187,029
Other	(2,775)	3,038
Net cash provided by financing activities	237,742	200,583
Net decrease in cash and cash equivalents	(77,915)	(34,350)
Cash and cash equivalents at beginning of period	298,565	443,671
Cash and cash equivalents at end of period	\$ 220,650	\$ 409,321
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	\$ 69,269	\$ 115,719
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	\$ (19,846)	\$ (14,733)

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

Oglethorpe Power Corporation
Notes to Unaudited Condensed Financial Statements
For the Three and Six Months ended June 30, 2013 and 2012

- (A) *General.* The condensed 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, the results for the three- and six-month periods ended June 30, 2013 and 2012. 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. Certain prior year amounts have been reclassified to conform with the current year presentation. These condensed financial statements should be read in conjunction with the financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012, as filed with the SEC. The results of operations for the three- and six-month periods ended June 30, 2013 are not necessarily indicative of results to be expected for the full year. As noted in our 2012 Form 10-K, our revenues consist primarily of sales to our 38 electric distribution cooperative members and, thus, the receivables on the condensed balance sheets are principally from our members. (See “Notes to Financial Statements” in our 2012 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 or comparable utility, adjusted for obsolescence.

The tables below detail assets and liabilities measured at fair value on a recurring basis at June 30, 2013 and December 31, 2012.

		Fair Value Measurements at Reporting Date Using		
		Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
	June 30, 2013	(Level 1)	(Level 2)	(Level 3)
		(dollars in thousands)		
Nuclear decommissioning trust funds:				
Domestic equity	\$134,766	\$134,766	\$ —	\$ —
International equity	47,471	47,471	—	—
Corporate bonds	37,981	—	37,981	—
US Treasury and government agency securities	49,787	49,787	—	—
Agency mortgage and asset backed securities	27,904	—	27,904	—
Municipal Bonds	655	—	655	—
Other	13,026	13,026	—	—
Long-term investments:				
Corporate bonds	4,856	—	4,856	—
US Treasury and government agency securities	7,096	7,096	—	—
Agency mortgage and asset backed securities	3,226	—	3,226	—
International equity	8,287	8,287	—	—
Mutual funds	53,761	53,761	—	—
Other	408	408	—	—
Interest rate options	43,680	—	—	43,680 ⁽¹⁾
Natural gas swaps	(3,114)	—	(3,114)	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2012	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
		(Level 1)	(Level 2)	(Level 3)
		(dollars in thousands)		
Nuclear decommissioning trust funds:				
Domestic equity	\$118,329	\$118,329	\$ —	\$ —
International equity	48,105	48,105	—	—
Corporate bonds	53,172	—	53,172	—
US Treasury and government agency securities	46,626	46,626	—	—
Agency mortgage and asset backed securities	21,273	—	21,273	—
Other	13,280	13,280	—	—
Long-term investments:				
Corporate bonds	5,762	—	5,762	—
US Treasury and government agency securities	7,387	7,387	—	—
Agency mortgage and asset backed securities	2,526	—	2,526	—
Mutual funds	60,972	60,972	—	—
Other	375	375	—	—
Bond, reserve and construction funds . . .	1	1	—	—
Interest rate options	25,783	—	—	25,783 ⁽¹⁾
Natural gas swaps	(1,085)	—	(1,085)	—

⁽¹⁾ Interest rate options as reflected on the unaudited condensed Balance Sheet include the fair value of the interest rate options offset by \$36,070,000 and \$8,950,000 of collateral received from the counterparties at June 30, 2013 and December 31, 2012, respectively.

The Level 2 investments above in corporate bonds and agency mortgage and asset backed securities may not be exchanged traded. The fair value measurements for these investments are based on a market approach, including the use of observable inputs. Common inputs include reported trades and broker/dealer bid/ask prices.

The following tables present the changes in our Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012.

	Three Months Ended June 30, 2013
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at March 31, 2013	\$26,539
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	17,141
Balance at June 30, 2013	<u>\$43,680</u>

	Three Months Ended June 30, 2012
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at March 31, 2012	\$ 66,860
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(27,645)
Balance at June 30, 2012	<u>\$ 39,215</u>

	Six Months Ended June 30, 2013
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at December 31, 2012	\$25,783
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	17,897
Balance at June 30, 2013	<u>\$43,680</u>

	Six Months Ended June 30, 2012		
	Decommissioning funds	Long-term investments	Interest Rate Options
	(dollars in thousands)		
Assets (Liabilities):			
Balance at December 31, 2011	\$(982)	\$ 7,713	\$ 69,446
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets)	982	—	(30,231)
Impairment included in other comprehensive margin (deficit)	—	887	—
Liquidations	—	(8,600)	—
Balance at June 30, 2012	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 39,215</u>

The estimated fair values of our long-term debt, including current maturities at June 30, 2013 and December 31, 2012 were as follows (in thousands):

	2013		2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	\$6,207,299	\$6,788,908	\$5,930,449	\$7,213,365

The fair value of long-term debt is Level 2 and is estimated based on observed or quoted market prices for the same or similar issues or on the current rates offered to us for debt of similar maturities. Our three primary sources of long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC) and by CoBank, ACB in addition to a multi-year term loan with Bank of Tokyo. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from a third party subscription 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, 2013 plus 1/8 percent, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank. We use an interest rate quote sheet provided by CoBank for valuation of the CoBank debt, which reflects current rates for a similar loan. The rates on the CFC debt are fixed and the valuation is based on rate quotes provided by CFC. The rate in effect at June 30, 2013 for our term loan, which resets each month and is based on a spread to LIBOR, was used for valuation of the term loan.

We use the methods and assumptions described above to estimate the fair value of each class of financial instruments. For cash and cash equivalents, restricted cash and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments.

- (C) *Derivative Instruments.* Our risk management and compliance committee provides general oversight over all risk management and compliance activities, including but not limited to, commodity trading, investment portfolio management and interest rate risk management. We use commodity trading derivatives to manage our exposure to fluctuations in the market price of natural gas. Prior to December 2012, our commodity trading derivatives were designated as hedging instruments under authoritative guidance for accounting for derivatives and hedging. In December 2012, we discontinued hedge accounting for these derivatives and began applying regulatory accounting. Consistent with our rate-making, unrealized gains or losses on natural gas swaps are reflected as a regulatory asset or liability. To hedge the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, we have entered into interest rate options. Hedge accounting is not applied to our interest rate options. Consistent with our rate-making, unrealized losses from the interest rate options are recorded as a regulatory asset. Within our nuclear decommissioning trust fund, derivatives including options, swaps and credit default swaps which are non-speculative, could be utilized to mitigate volatility associated with duration, default, yield curve and the interest rate risks of the portfolio. Consistent with our rate-making, unrealized gains or losses related to the decommissioning trust funds are recorded as an increase or decrease in the associated regulatory asset or liability. We do not hold or enter into derivative transactions for trading or speculative purposes.

We are exposed to credit risk as a result of entering into these hedging arrangements. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. We have established policies and procedures to manage credit risk through counterparty analysis, exposure calculation and monitoring, exposure limits, collateralization and certain other contractual provisions.

It is possible that volatility in commodity prices and/or interest rates could cause us to have credit risk exposures with one or more counterparties. We currently have credit risk exposure to our interest rate options counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of June 30, 2013, all of the counterparties with transaction amounts outstanding under our hedging programs are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

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

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

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

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

At June 30, 2013 and December 31, 2012, the estimated fair values of our natural gas contracts were net liabilities of approximately \$3,114,000 and \$1,085,000, respectively.

As of June 30, 2013 and December 31, 2012, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on June 30, 2013 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit totaling up to \$2,761,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of June 30, 2013 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2013	7.3
2014	1.6
2015	0.1
Total	9.0

Interest rate options. We are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4. In fourth quarter of 2011, we purchased LIBOR swaptions at a cost of \$100,000,000 to hedge the interest rates on

approximately \$2.2 billion of the expected debt that will be used to finance two additional nuclear units at Plant Vogtle. As of June 30, 2013, our outstanding swaptions hedged approximately \$1.8 billion of the expected debt for the new Vogtle units.

The LIBOR swaptions are each designed to cap our effective interest rate at a specified fixed interest rate on a specified option expiration date. This is accomplished by means of a payment of the cash settlement value our counterparties are obligated to make to us if prevailing fixed LIBOR swap rates exceed the specified fixed rate on the option expiration date. This payment would partially offset our interest costs, thereby reducing our effective interest rate. The cash settlement value would be zero if swap rates are at or below the specified fixed rate on the expiration date. The cash settlement value is calculated based on the value of an underlying swap which we have the right, but not the obligation, to enter into, which would begin on the option expiration date and extend until 2042 and under which we would pay the specified fixed rate and receive a floating LIBOR rate. The fixed rates on the unexpired swaptions we hold are in the range of 50 to 150 basis points above LIBOR swap rates that were in effect as of June 30, 2013 and the weighted average fixed rate is 4.15%. Swaptions, having notional amounts totaling \$373,396,000 expired without value during the six months ended June 30, 2013. The remaining swaptions expire quarterly through 2017.

We paid all the premiums to purchase these LIBOR swaptions at the time we entered into these transactions and have no additional payment obligations. These derivatives are recorded at fair value, and hedge accounting is not applied. At June 30, 2013 and December 31, 2012, the fair value of these swaptions was approximately \$43,680,000 and \$25,783,000, respectively. To manage our credit exposure to our counterparties, we negotiated credit support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the swaptions outstanding for that counterparty exceeds a certain threshold. The collateral thresholds can range from \$0 to \$10,000,000 depending on each counterparty's credit rating. As of June 30, 2013 and December 31, 2012, we held \$36,070,000 and \$8,950,000 of funds posted as collateral by the counterparties, respectively. The collateral received is recorded as restricted cash on our balance sheet. The liability associated with the collateral is recorded as an offset to the fair values of the swaptions, which are recorded within other deferred charges on the balance sheet, resulting in a net carrying amount of the interest rate options of \$7,610,000 and \$16,833,000 at June 30, 2013 and December 31, 2012, respectively.

We are deferring gains or losses from the change in fair value of each LIBOR swaption and related carrying and other incidental costs in accordance with our rate-making treatment. The deferred costs and deferred gains, if any, from the settlement of the interest rate options will be amortized and collected in rates over the life of the \$2.2 billion of debt that we hedged with the swaptions.

We estimate the value of the LIBOR swaptions utilizing an option pricing model based on several inputs including the notional amount, the forward LIBOR swap rates, the option volatility, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, as well as credit attributes, including the credit spread of the counterparty and the amount of credit support that is available for each swaption. The fair value of the swaptions is sensitive to certain of these inputs, especially option volatility. We are able to effectively observe all of these factors using a variety of market sources except for the credit spreads of certain counterparties and the option volatility. We are able to estimate option volatility implied by valuations we obtain from various sources, but the valuations, and therefore the implied option volatilities, vary considerably from one source to another. Since valuations of comparable instruments are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We considered both any intrinsic value and the remaining time value associated with the derivatives and considered counterparty credit risk in our determination of all estimated fair

values. We believe the estimated fair values for the LIBOR swaptions we hold are based on the most accurate information available for these types of derivative contracts. The following table reflects the remaining notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of June 30, 2013.

Year	LIBOR Swaption Notional Dollar Amount (in thousands)
2013	\$ 381,056
2014	563,425
2015	470,625
2016	310,533
2017	80,169
Total	\$1,805,808

The table below reflects the fair value of derivative instruments and their effect on our condensed balance sheets at June 30, 2013 and December 31, 2012.

	Balance Sheet Location	Fair Value	
		2013	2012
		(dollars in thousands)	
Not designated as hedges:			
Assets:			
Interest rate options ⁽¹⁾	Other deferred charges	\$43,680	\$25,783
Liabilities:			
Natural gas swaps	Other current liabilities	\$ 3,114	\$ 1,085

⁽¹⁾ Excludes liability associated with cash collateral of \$36,070,000 and \$8,950,000 as of June 30, 2013 and December 31, 2012, respectively, which is recorded as an offset to the fair value of the swaptions on the unaudited Condensed Balance Sheets.

The following table presents the gross realized gains and (losses) on derivative instruments recognized in margin for the three and six months ended June 30, 2013 and 2012.

	Statement of Revenues and Expenses Location	Three months ended June 30, 20132012		Six months ended June 30, 20132012	
(dollars in thousands)					
Designated as hedges:					
Natural Gas Swaps	Fuel	\$ —	\$ 149	\$ —	\$ 149
Natural Gas Swaps	Fuel	—	(3,095)	—	(5,502)
Not Designated as hedges:					
Natural Gas Swaps	Fuel	449	—	566	—
Natural Gas Swaps	Fuel	(379)	—	(913)	—
		\$ 70	\$(2,946)	\$(347)	\$(5,353)

The following table presents the gross unrealized gains and (losses) on derivative instruments deferred on the balance sheet at June 30, 2013 and December 31, 2012.

	Balance Sheet Location	2013	2012
		(dollars in thousands)	
Not designated as hedges:			
Interest rate options	Regulatory asset	\$(47,085)	\$(74,217)
Natural gas swaps	Regulatory asset	—	(1,085)
Natural gas swaps	Regulatory liability	(3,114)	—
		\$(50,199)	\$(75,302)

The following table presents the gross amounts of derivatives and their related offset amounts as permitted by their respective master netting agreements and obligations to return cash collateral at June 30, 2013.

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts offset on the Balance Sheet	Cash Collateral	Net Amounts of Assets Presented on the Balance Sheet
(dollars in thousands)				
Assets:				
Natural gas swaps	\$(3,151)	\$37	\$ —	\$(3,114)
Interest rate options	\$43,680	\$—	\$(36,070)	\$ 7,610

(D) *Investments in Debt and Equity Securities.* Investment securities we hold are classified as available-for-sale. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from other comprehensive margin, except that, in accordance with our rate-making treatment, unrealized gains and losses from investment securities held in the nuclear decommissioning trust fund are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 72% of these gross unrealized losses were in effect for less than one year.

The following tables summarize the activities for available-for-sale securities as of June 30, 2013 and December 31, 2012.

June 30, 2013	Gross Unrealized (dollars in thousands)			Fair Value
	Cost	Gains	Losses	
Equity	\$172,916	\$45,712	\$ (4,608)	\$214,020
Debt	164,014	6,919	(9,164)	161,769
Other	13,439	—	(4)	13,435
Total	\$350,369	\$52,631	\$(13,776)	\$389,224

December 31, 2012	Gross Unrealized (dollars in thousands)			Fair Value
	Cost	Gains	Losses	
Equity	\$153,846	\$45,071	\$(3,675)	\$195,242
Debt	163,127	10,286	(4,501)	168,912
Other	13,654	—	—	13,654
Total	\$330,627	\$55,357	\$(8,176)	\$377,808

(E) *Recently Issued or Adopted Accounting Pronouncements.* In December 2011, the Financial Accounting Standards Board (FASB) issued “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities,” which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. The adoption of this standard was effective for us January 1, 2013 and did not have a material impact on our consolidated financial statements.

In February 2013, the FASB issued “Comprehensive Income (Topic 220): Reporting Amounts Reclassified out of Accumulated Other Comprehensive Income,” which amended certain provisions of ASC 220 “Comprehensive Income.” The update requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective items on the income statement for reclassified amounts that are required by U.S. GAAP to be reclassified entirely to net income. The update also requires additional footnote disclosures for reclassified amounts that are not required by U.S. GAAP to be reclassified entirely to net income. The adoption of this standard did not have a material impact on our consolidated financial statements.

(F) *Accumulated Comprehensive Margin.* The table below provides detail of the beginning and ending balance for each classification of other comprehensive margin (deficit) along with the amount of any reclassification adjustments included in margin for each of the periods presented in the unaudited Condensed Statements of Patronage Capital and Membership Fees and Accumulated Other Comprehensive Margin. There were no material changes in the nature, timing or amounts of expected (gain) loss reclassified to net margin from the amounts disclosed in our 2012 Form 10-K. Amounts reclassified to net margin in the table below are reflected in “Other income” on our unaudited Condensed Statement of Revenues and Expenses.

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

	Accumulated Other Comprehensive Margin Three Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at March 31, 2012	\$1,327
Unrealized gain	119
Balance at June 30, 2012	<u>\$1,446</u>
Balance at March 31, 2013	\$ 691
Unrealized (loss)	(1,074)
(Gain) reclassified to net margin	(16)
Balance at June 30, 2013	<u>\$ (399)</u>

	Accumulated Other Comprehensive Margin (Deficit) Six Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at December 31, 2011	\$ 618
Unrealized gain	911
(Gain) reclassified to net margin	(83)
Balance at June 30, 2012	<u>\$1,446</u>
Balance at December 31, 2012	\$ 903
Unrealized (loss)	(1,222)
(Gain) reclassified to net margin	(80)
Balance at June 30, 2013	<u>\$ (399)</u>

(G) Contingencies and Regulatory Matters.

General

We are subject to certain claims and legal actions arising in the ordinary course of our business. The ultimate outcome of any pending or current proceedings against us cannot be predicted at this time; however, except as discussed in “—*Nuclear Construction*” below, management does not anticipate that the liabilities, if any, for any current proceedings against us, if adversely determined, will have a material effect on our financial condition or results of operations.

Nuclear Construction

In April 2008, Georgia Power Company, acting for itself and as agent for Oglethorpe, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia (collectively, the Co-owners), and Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, the Contractor) entered into an engineering, procurement, and construction agreement (Vogtle No. 3 and No. 4 Agreement) to design, engineer, procure, and construct two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle Units No. 3 and No. 4).

Under the Vogtle No. 3 and No. 4 Agreement, the Co-owners and the Contractor have established both informal and formal dispute resolution procedures in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, has successfully initiated both formal and informal claims through these procedures, including ongoing claims. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and the Co-owners are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

The most significant litigation relates to costs associated with design changes to the Westinghouse AP1000 Design Control Document (DCD) and costs associated with delays in the project schedule related to the timing of approval of the DCD and issuance of the combined construction permits and operating licenses by the Nuclear Regulatory Commission. In July 2012, the Co-owners and Contractor began negotiations regarding these costs, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the contract. The Contractor has claimed that its estimated adjustment attributable to us, based on our ownership interest, is approximately \$280,000,000 in 2008 dollars with respect to these issues. The Contractor has also asserted that it is entitled to schedule extensions. Georgia Power, on behalf of the Co-owners, has not agreed with either the proposed cost or schedule adjustments or that the Co-owners have any responsibility for costs related to these issues. On November 1, 2012, the Co-owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia, seeking a declaratory judgment that the Co-owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Co-owners in the U.S. District Court for the District of Columbia alleging the Co-owners are responsible for these costs. Georgia Power and the Co-owners intend to vigorously defend their positions. During litigation, Georgia Power and the Co-owners expect negotiations with the Contractor to continue with respect to cost and schedule during which time the parties will attempt to reach a mutually acceptable compromise of their positions. If any or all of these costs are ultimately imposed on the Co-owners, we will capitalize the costs attributable to us. As of June 30, 2013, no material amounts have been recorded related to this claim. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction.

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

Environmental Matters

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

In general, these and other types of environmental requirements are becoming increasingly stringent. Such requirements may substantially increase the cost of electric service, by requiring

modifications in the design or operation of existing facilities, the purchase of emission allowances, or changes or delays in the location, design, construction or operation of new facilities. Failure to comply with these requirements could result in civil and criminal penalties and could include the complete shutdown of individual generating units not in compliance. Certain of our debt instruments require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current or future environmental laws or regulations. Should we fail to be in compliance with these requirements, it would constitute a default under those debt instruments. 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. For example, in January 2013, several plaintiffs filed complaints against us and the other co-owners of Plant Scherer claiming personal injury and property damage arising from the alleged release of hazardous substances from the plant, primarily related to the coal-ash pond, into the surrounding groundwater and air.

- (H) *Restricted Cash.* At June 30, 2013 and December 31, 2012, we had restricted cash totaling \$36,230,000 and \$9,109,000, respectively, of which \$36,074,000 and \$8,953,000, respectively, was classified as long-term. The long-term restricted cash balance at June 30, 2013 and December 31, 2012 consisted primarily of funds posted as collateral by counterparties to our interest rate options.
- (I) *Restricted Short-term Investments.* At June 30, 2013 and December 31, 2012, we had \$206,211,000 and \$64,671,000, respectively, on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted funds will be utilized for future Rural Utilities Service Federal Financing Bank debt service payments. The deposit earns interest at a Rural Utilities Service guaranteed rate of 5% per annum.
- (J) *Regulatory Assets and Liabilities.* We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery from our members in future revenues through rates under the wholesale power contracts with our members extending through December 31, 2050. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from our members.

The following regulatory assets and liabilities are reflected on the accompanying condensed balance sheet as of June 30, 2013 and December 31, 2012.

	2013	2012
	(dollars in thousands)	
<i>Regulatory Assets:</i>		
Premium and loss on reacquired debt ^(a)	\$ 80,534	\$ 86,319
Amortization on capital leases ^(b)	22,364	28,670
Outage costs ^(c)	43,700	30,901
Interest rate swap termination fees ^(d)	15,331	17,326
Asset retirement obligations ^(e)	7,914	11,382
Depreciation expense ^(f)	49,073	49,785
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs ^(g)	25,668	23,030
Interest rate options cost ^(h)	58,304	75,716
Deferral of effects on net margin—Smith Energy Facility ⁽ⁱ⁾	44,207	21,394
Other regulatory assets ^(j)	9,500	8,379
<i>Total Regulatory Assets</i>	<u>\$356,595</u>	<u>\$352,902</u>
<i>Regulatory Liabilities:</i>		
Accumulated retirement costs for other obligations ^(e)	\$ 25,304	\$ 28,846
Deferral of effects on net margin—Hawk Road Energy Facility ⁽ⁱ⁾	21,208	17,113
Major maintenance sinking fund ^(k)	27,680	30,948
Deferred debt service adder ^(l)	52,349	47,486
Other regulatory liabilities ^(j)	5,278	5,592
<i>Total Regulatory Liabilities</i>	<u>\$131,819</u>	<u>\$129,985</u>
<i>Net Regulatory Assets</i>	<u>\$224,776</u>	<u>\$222,917</u>

- (a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt amortized over the period of the refunding debt, which range up to 30 years.
- (b) Represents the difference between lease payments and the aggregate of the amortization on the capital lease assets and the interest on the capital lease obligations for rate-making purposes. Recovered over the remaining terms of the leases through 2031.
- (c) Consists of both coal-fired and nuclear refueling outage costs. Coal-fired outages are amortized on a straight-line basis to expense over an 18 to 36-month period. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 to 24-month operating cycles of each unit.
- (d) Represents losses on settled interest rate swaps arrangements that are being amortized through 2016 and 2019.
- (e) Represents difference in timing of recognition of the costs of decommissioning for financial statement purposes and for ratemaking purposes.
- (f) Prior to Nuclear Regulatory Commission (NRC) approval of a 20-year license extension for Plant Vogtle, we deferred the difference between Plant Vogtle depreciation expense based on the then 40-year operating license and depreciation expense assuming an expected 20-year license extension. Amortization commenced upon NRC approval of the license extension in 2009 and is being amortized over the remaining life of the plant.
- (g) Deferred charges related to Vogtle Units No. 3 and No. 4 training and interest related carrying costs of such training. Amortization will commence effective with the commercial operation date of each unit and amortized to expense over the life of the units.
- (h) Deferral of net loss associated with the change in fair value of the interest rate options to hedge interest rates on a portion of expected borrowings related to Vogtle Units No. 3 and No. 4 construction. Amortization will commence effective with the expected principal repayment of the Department of Energy (DOE)-guaranteed loan and amortized over the expected remaining life of the DOE-guaranteed loan which will finance a portion of the construction project.
- (i) Effects on net margin for Smith and Hawk Road Energy Facilities are deferred until the end of 2015 and will be amortized over the remaining life of each respective plant.
- (j) The amortization period for other regulatory assets range up to 36 years and the amortization period of other regulatory liabilities range up to 13 years.
- (k) Represents collections for future major maintenance costs; revenues to be recognized as major maintenance costs are incurred.
- (l) Collections to fund debt payments in excess of depreciation expense through the end of 2025; deferred revenues will be amortized over the remaining useful life of the plants.

- (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. At June 30, 2013, member power bill prepayments as reflected on the unaudited condensed balance sheets are \$156,792,000, of which, \$124,090,000 is classified as current liabilities and \$32,702,000 as deferred credits and other liabilities. The prepayments are being applied against members' power bills through January 2018, with the majority of the remaining balance scheduled to be applied by the end of 2013.
- (L) *Debt.* On March 1, 2013, instead of remarketing the \$212,760,000 of pollution control revenue bonds that were originally issued on our behalf by the Development Authorities of Appling, Burke and Monroe Counties, and were subject to mandatory tender, we elected to redeem the bonds with commercial paper. On April 23, 2013, the Development Authority of Appling County (Georgia), the Development Authority of Burke County (Georgia) and the Development Authority of Monroe County (Georgia) issued, on our behalf, \$212,760,000 in aggregate principal amount of tax-exempt pollution control revenue bonds for the purpose of refinancing costs associated with certain of our air or water pollution control and sewage or solid waste disposal facilities. The proceeds were used to repay the outstanding commercial paper utilized to redeem the pollution control revenue bonds that were redeemed on March 1, 2013. Each series of bonds bear interest at 2.40% per annum until April 1, 2020, the initial mandatory tender date. The pollution control revenue bonds are scheduled to mature in 2038 through 2040. Our payment obligations related to these bonds are secured under our first mortgage indenture.

For the six month period ended June 30, 2013, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling \$70,408,000 for general and environmental improvements at existing plants.

In July 2013, we received an additional \$589,605,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for the long-term financing of the Smith Energy Facility and general improvements at existing plants. A portion of these advances was utilized to repay \$232,610,000 of outstanding commercial paper classified as long-term debt at June 30, 2013.

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 through a combination of our generation assets and, to a lesser extent, power purchased from power marketers and other suppliers. As with cooperatives generally, we operate on a not-for-profit basis.

Results of Operations

For the Three and Six Months Ended June 30, 2013 and 2012

Net Margin

Throughout the year, we monitor our operating results and, with board approval, make budget adjustments when and as necessary to ensure our targeted margins for interest ratio is achieved. Under our first mortgage indenture, we are required to establish and collect rates that are reasonably expected, together with our other revenues, to yield at least a 1.10 margins for interest ratio in each fiscal year. However, to enhance margin coverage during a period of increased capital requirements, our board of directors approved budgets for 2012 and 2013 to achieve a 1.14 margins for interest ratio. As our capital requirements continue to evolve, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

Our net margin for the three-month and six-month periods ended June 30, 2013 was \$24.5 million and \$46.5 million compared to \$10.9 million and \$24.4 million for the same periods of 2012. Through June 30, 2013, we collected approximately 112% of our targeted net margin of \$41.5 million for the year ending December 31, 2013. Actual net margins exceeding targeted margins during the fiscal year is typical as our capacity revenues are recorded evenly throughout the year and our management generally budgets conservatively. We anticipate our board will approve a budget adjustment by the end of the year so that net margins will achieve, but not exceed, the targeted margins for interest ratio.

Operating Revenues

Our operating revenues fluctuate from period to period based on several factors, including 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.

Sales to Members. Total revenues from sales to members decreased 1.4% and 2.1% in the three-month and six-month periods ended June 30, 2013 compared to the same periods of 2012. Megawatt-hour sales to members decreased 14.9% and 13.4% for the three-month and six-month periods ended June 30, 2013 compared to the same periods of 2012. The average total revenue per megawatt-hour from sales to members increased 15.9% and 13.1% for the three-month and six-month periods ended June 30, 2013 compared to the same period of 2012.

The components of member revenues for the three-month and six-month periods ended June 30, 2013 and 2012 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Capacity revenues	\$ 184,261	\$ 173,446	\$ 365,375	\$ 347,633
Energy revenues	121,930	137,037	227,469	258,080
Total	<u>\$ 306,191</u>	<u>\$ 310,483</u>	<u>\$ 592,844</u>	<u>\$ 605,713</u>
Kilowatt-hours sold to members	4,732,825	5,563,074	8,886,487	10,265,873
Cents per kilowatt-hour	6.47¢	5.58¢	6.67¢	5.90¢

Capacity revenues from members increased 6.2% and 5.1% for the three-month and six-month periods ended June 30, 2013 compared to the same periods of 2012. Capacity revenues relate primarily to the assignment to each of our members the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges. Each member is required to pay us for capacity furnished under its wholesale power contract in accordance with rates we establish. Our capacity revenues are based on the costs we expect to incur on an annual basis and are subject to adjustment by our board such that our net margins will achieve, but not exceed, the targeted margins for interest ratio. See “—*Net Margin*” for discussion regarding margins for interest ratio.

Energy revenues were 11.0% and 11.9% lower for the three-month and six-month periods ended June 30, 2013 compared to the same periods of 2012. Our average energy revenue per megawatt-hour from sales to members increased 4.6% and 1.8% for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012. The decrease in energy revenues for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012 resulted primarily from lower coal-fired and natural gas generation partially offset by higher fuel costs per megawatt-hour due to higher natural gas prices. For a discussion of total fuel costs and total generation, see “—*Operating Expenses*.”

Sales to Non-Members. Sales to non-members for the three-month and six-month periods ended June 30, 2013 were 51.2% and 38.9% lower as compared to the same periods of 2012. Sales to non-members in 2012 consisted of capacity and energy sales made under an agreement to sell the entire output of Unit No. 1 of the Thomas A. Smith Energy Facility to Georgia Power Company through May 31, 2012, as well as energy sales to other non-members from Smith Units No. 1 and No. 2. The decrease for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012 was primarily due to the expiration of this agreement with Georgia Power. This decrease was partially offset by increased energy sales to other non-members.

Operating Expenses

Operating expenses for the three-month and six-month periods ended June 30, 2013 decreased 10.3% and 8.9% as compared to the same periods of 2012. This decrease was primarily due to lower fuel costs and lower depreciation and amortization expenses offset somewhat by higher purchased power costs and accretion expense.

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

Fuel Source	Three Months Ended June 30,					
	2013			2012		
	Cost (thousands)	Generation (MWh)	Cost per MWh	Cost (thousands)	Generation (MWh)	Cost per MWh
Coal	\$ 45,167	1,490,279	\$30.31	\$ 65,319	2,069,400	\$31.56
Nuclear	22,598	2,574,270	8.78	17,702	2,612,822	6.78
Gas:						
Combined Cycle	41,532	1,142,648	36.35	45,299	1,991,583	22.75
Combustion Turbine	3,768	47,568	79.21	10,868	275,745	39.41
	<u>\$113,065</u>	<u>5,254,765</u>	<u>\$21.52</u>	<u>\$139,188</u>	<u>6,949,550</u>	<u>\$20.03</u>

Fuel Source	Six Months Ended June 30,					
	2013			2012		
	Cost (thousands)	Generation (MWh)	Cost per MWh	Cost (thousands)	Generation (MWh)	Cost per MWh
Coal	\$ 85,812	2,974,233	\$28.85	\$118,905	3,748,595	\$31.72
Nuclear	40,930	4,659,362	8.78	38,033	5,046,539	7.54
Gas:						
Combined Cycle	81,670	2,419,201	33.76	80,170	3,381,051	23.71
Combustion Turbine	4,803	64,332	74.66	11,308	282,489	40.03
	<u>\$213,215</u>	<u>10,117,128</u>	<u>\$21.07</u>	<u>\$248,416</u>	<u>12,458,674</u>	<u>\$19.94</u>

For the three-month and six-month periods ended June 30, 2013, total fuel costs decreased 18.8% and 14.2% and megawatt-hour generation from these fuel sources decreased 24.4% and 18.8%, respectively, compared to the same periods of 2012. Average fuel costs per megawatt-hour increased 7.4% and 5.7% in the three-month and six-month periods ended June 30, 2013 compared to the same periods of 2012. The decrease in total fuel costs was primarily due to lower generation at Plant Wansley and our natural gas-fired facilities. Plant Wansley, which is fueled by higher cost eastern coal, was in reserve shutdown for most of the six-month period ended June 30, 2013 primarily due to more economical generation from our natural gas-fired facilities. Generation from gas-fired facilities also decreased in the three-month and six-month periods ended June 30, 2013 versus the same periods of 2012 primarily due to lower utilization of the Smith Energy Facility, although all of our gas-fired facilities experienced decreased generation in the first half of 2013 compared to the same period of 2012. The decrease in total fuel costs was partially offset by increased natural gas prices in 2013. As was the case in 2012, generation from Smith continues to be sold to non-members.

Total production costs decreased 2.3% for the six-month period ended June 30, 2013 as compared to the same period of 2012. This decrease resulted primarily from lower production costs for Hawk Road Energy Facility in 2013 as production costs in 2012 included planned outage work.

Depreciation and amortization costs decreased 4.9% and 11.1% for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012. This decrease was primarily due to the May 2012 completion of amortization of the intangible asset associated with a purchase and sale agreement with Georgia Power which was acquired as part of the Smith acquisition. In addition,

amortization expense of leasehold improvements for Scherer Unit No. 2 capital leases decreased because we extended the lease terms in June 2012.

Purchased power costs increased 24.5% and 14.4% for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012. The increase in purchased power resulted primarily from increased cost per kilowatt-hour acquired under our energy replacement program, which replaces power from our owned generation facilities with power purchased on the spot market at a lower price. In addition, increased transmission expenses contributed to the higher purchased power costs.

Accretion expense increased 16.8% and 16.4% for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012. The increase in accretion expense resulted primarily from an increase in the asset retirement obligation for the decommissioning of our ash ponds based on December 2012 studies.

The effect on net margin of Smith and Hawk Road is being deferred until 2016 at which time the amounts will be amortized over the remaining life of the plants. In implementing the deferral plans, we assumed that our members would generally not require energy from the plants until 2016. The change in the deferral resulted primarily from the expiration of the power purchase and sale agreement with Georgia Power that ended in May 2012.

Other Income

Investment income increased 5.0% and decreased 3.7% for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012. An increase in funds deposited in the Rural Utilities Service Cushion of Credit Account as well as increased investment income from nuclear decommissioning trust funds contributed to the higher investment income in the second quarter of 2013. The termination of 90% of the Rocky Mountain lease transactions during the second half of 2012 contributed to the decrease in investment income during the six-month period ended June 30, 2013.

Other income decreased 29.0% and 34.5% for the three-month and six-month periods ended June 30, 2013 as compared to the same periods of 2012. This decrease was primarily due to lower amortization of gain on Rocky Mountain lease transactions due to the 2012 terminations discussed above. In addition, the amortization of the gain associated with the Scherer Unit No. 2 capital leases was lower due to extension of the terms of the leases in 2012.

Interest charges

Allowance for debt funds used during construction increased 22.7% and 22.2% in the three-month and six-month periods ended June 30, 2013 compared to the same periods of 2012 primarily due to construction expenditures for Vogtle Units No. 3 and No. 4.

Financial Condition

Balance Sheet Analysis as of June 30, 2013

Assets

Cash used for property additions for the six-month period ended June 30, 2013 totaled \$321.2 million. Of this amount, approximately \$182 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, approximately \$46 million for environmental control systems being installed primarily at Plant Scherer and approximately \$28 million for nuclear fuel purchases. The remaining expenditures were for normal additions and replacements to existing generation facilities.

The \$206.2 million of restricted short-term investments at June 30, 2013 represent funds deposited into a Rural Utilities Service Cushion of Credit Account with the U.S. Treasury and earns interest at a guaranteed rate of 5% per annum. The funds, including interest earned thereon, can only be applied to debt service on Rural Utilities Service and Rural Utilities Service-guaranteed Federal Financing Bank notes. Decisions regarding when to apply the funds are guided by the interest rate environment and our anticipated liquidity needs.

Equity and Liabilities

Long-term debt and capital leases due within one year increased \$292.2 million during the six-month period ended June 30, 2013 primarily due to the reclassification of a \$260.0 million term loan due in April 2014.

Accounts payable decreased \$66.9 million in the six-month period ended June 30, 2013. The December 31, 2012 payables balance included \$25.2 million in credits due to the members for a board approved reduction to 2012 revenue requirements as a result of margins collected in excess of our 2012 target. These credits were applied to the members' bills in the first quarter of 2013. The decrease was also the result of a \$32.3 million decrease in the payable to Georgia Power for operation and maintenance costs for our co-owned plants and capital costs associated with Vogtle Units No. 3 and No. 4 construction. In addition, there was \$15.4 million decrease in accounts payable trade accounts primarily related to property tax payments.

Member power bill prepayments represent funds received from the members for the prepayment of their monthly power bills. At June 30, 2013, \$124.1 million of member power bill prepayments was classified as a current liability and \$32.7 million was classified as a long-term liability. During the six-month period ended June 30, 2013, \$96.7 million of prepayments were received from the members and \$46.0 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note K of Notes to Unaudited Condensed Financial Statements and “—Capital Requirements and Liquidity and Sources of Capital—*Liquidity*.”

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4.

We, along with Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton are participating in the construction of two Westinghouse AP1000 nuclear generating units at Plant Vogtle, each with a nominally rated generating capacity of approximately 1,100 megawatts. Our ownership interest is 30%, representing 660 megawatts of total capacity. As of June 30, 2013, our total capitalized costs to date for Vogtle Units No. 3 and No. 4 were \$1.9 billion. For additional information about the Vogtle construction project, see “Item 1—BUSINESS—OUR POWER SUPPLY RESOURCES—Future Power Resources—*Plant Vogtle Units No. 3 and No. 4*” and “Item 7—MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*” in our 2012 Form 10-K.

Environmental Regulations

The Environmental Protection Agency, or EPA, continues to develop a number of rules that significantly expand the scope of regulation of air emissions, water intake and waste management at power plants.

In June, the President announced his Climate Action Plan to reduce domestic emissions of greenhouse gases by 17% below 2005 levels by 2020. Underpinning the plan is a focus on carbon emissions from power plants. On June 25, 2013, a Presidential Memorandum directed the Administrator of the EPA to perform two tasks: (1) to re-propose New Source Performance Standards (NSPS) for greenhouse gas emissions from new power plants by September 20, 2013 which would replace or modify the NSPS proposed on April 13, 2012, and to finalize the September proposal in a timely fashion; and (2) to propose NSPS for modified, reconstructed and existing power plants by June 1, 2014, finalize those NSPS by June 1, 2015 and require states to submit plans for implementing those finalized NSPS by June 30, 2016. The effects of these actions on our facilities cannot be determined at this time and will depend on further rulemaking and any litigation brought to challenge any final federal or state rules.

For further 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 2012 Form 10-K.

Liquidity

At June 30, 2013, we had \$1.123 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included \$221 million in cash and cash equivalents and \$902 million of unused and available committed credit arrangements.

At June 30, 2013, we had in excess of \$1.9 billion of committed credit arrangements in place, comprised of the five separate facilities reflected in the table below.

Committed Credit Facilities			
	Authorized Amount	Available 6/30/2013	Expiration Date
	(dollars in millions)		
<i>Unsecured Facilities:</i>			
Syndicated Line of Credit led by Bank of America	\$1,265	\$358 ⁽¹⁾	June 2015
Syndicated Line of Credit led by CoBank	150	150	September 2014
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	34 ⁽²⁾	December 2013
<i>Secured facilities:</i>			
CFC Line of Credit ⁽³⁾	250	250	December 2013
Total	\$1,925	\$902	

⁽¹⁾ Of the portion of this facility that is unavailable, \$771.1 million is dedicated to support commercial paper we have issued and \$135.5 million relates to letters of credit issued under this facility to support variable rate demand bonds.

⁽²⁾ Of the portion of this facility that is unavailable, \$113.7 million relates to letters of credit issued under this facility to support variable rate demand bonds and \$2.3 million relates to letters of credit issued to post collateral to third parties.

⁽³⁾ This facility has a term loan option that can extend the maturity to December 31, 2043.

As of June 30, 2013, we were using our commercial paper program to provide interim funding for (i) payments related to the construction of Vogtle Units No. 3 and No. 4, (ii) a portion of the cost to acquire Smith, and (iii) the upfront payments made in connection with our interest rate hedging program.

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

Under our unsecured committed lines of credit, we have the ability to issue letters of credit totaling \$835 million in the aggregate, of which \$584 million remained available at June 30, 2013. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under our committed credit facilities for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue. The majority of our outstanding letters of credit are for the purpose of providing credit enhancement on variable rate demand bonds.

Between projected cash on hand and these credit arrangements, we believe we have sufficient liquidity to cover our normal operations and to provide interim financing for construction of Vogtle Units No. 3 and No. 4.

Several of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At June 30, 2013, the required minimum level was \$575 million and our actual patronage capital was \$720 million. Additional covenants contained in several of our credit facilities limit the amount of secured indebtedness and unsecured indebtedness we can have outstanding. At June 30, 2013, the most restrictive of these covenants limits our secured indebtedness to \$9.5 billion and our unsecured indebtedness to \$4.0 billion. At June 30, 2013, we had \$5.9 billion of secured indebtedness and \$1.2 billion of unsecured indebtedness outstanding, which was well within the covenant thresholds.

At June 30, 2013, current assets included \$206.2 million of restricted short-term investments pursuant to deposits made into a Rural Utilities Service Cushion of Credit Account. See “Balance Sheet Analysis” herein for more information regarding this account.

Financing Activities

First Mortgage Indenture. At June 30, 2013, we had \$5.7 billion of long-term debt outstanding under our first mortgage indenture secured equally and ratably by a lien on substantially all of our tangible and some of our intangible assets, including those we acquire in the future. See “Item 7—MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities—First Mortgage Indenture*” in our 2012 Form 10-K for a further discussion of our first mortgage indenture.

Bond Financing. On April 23, 2013, we issued \$212.8 million of pollution control revenue bonds through the Development Authorities of Appling, Burke and Monroe Counties and used the proceeds to repay a like amount of commercial paper that we issued on March 1, 2013. The proceeds from the commercial paper issuance were used to redeem \$212.8 million of pollution control revenue bonds previously issued by the development authorities on our behalf that we elected to redeem on March 1, 2013.

Rural Utilities Service-Guaranteed Loans. We currently have four approved Rural Utilities Service-guaranteed loans, totaling \$1.1 billion, which are being funded through the Federal Financing Bank and are in various stages of being drawn down, with \$298.3 million remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture. On July 9, 2013, we received a

\$492.6 advance under the loan covering the majority of the acquisition cost of Smith, a portion of which was utilized to repay \$232.6 million of outstanding commercial paper.

Department of Energy-Guaranteed Loan. In May 2010, we signed a conditional term sheet with the Department of Energy that sets forth the general terms of a loan and related loan guarantee that would fund up to \$3.057 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. We continue to work with the Department of Energy on this proposed financing; however, final approval and issuance of a loan guarantee is subject to negotiation of definitive agreements, completion of due diligence and satisfaction of other conditions. Therefore, there can be no assurance that the Department of Energy will ultimately issue the loan guarantee to us. We expect that we will fund any Vogtle costs not funded under the Department of Energy loan guarantee program through capital market financings. The conditional commitment has been extended by the Department of Energy to September 30, 2013.

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 2012 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 Condensed Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Not Applicable.

Item 4. Controls and Procedures

As of June 30, 2013, 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, 2013 that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

There have not been any material changes to legal proceedings from those reported in “Item 3—LEGAL PROCEEDINGS” of our 2012 Form 10-K.

Item 1A. Risk Factors

There have not been any material changes in our risk factors from those reported in “Item 1A—RISK FACTORS” of our 2012 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

Not Applicable.

Item 6. Exhibits

<u>Number</u>	<u>Description</u>
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Executive Officer and 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 Elizabeth B. Higgins (Principal Executive Officer and Principal Financial Officer).
101	XBRL Interactive Data File.

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 12, 2013

/s/ Elizabeth B. Higgins

Elizabeth B. Higgins
Executive Vice President and
Chief Financial Officer
(Duly Authorized Officer and Principal Financial
Officer)