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 September 30, 2014

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

OglethorpePower

(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
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2014

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" in our quarterly report for the quarterly period ended June 30, 2014 and under the heading "RISK FACTORS" and in other sections of our annual report on Form 10-K for the fiscal year ended December 31, 2013. 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 capital improvement and construction projects, in particular, 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 our continued eligibility to receive advances from the U.S. Department of Energy for construction of two additional nuclear units at Plant Vogtle;
- 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;
- litigation or legal and administrative proceedings and settlements;
- 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;
- 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)
September 30, 2014 and December 31, 2013

	(dollars in thousands)	
	2014	2013
Assets		
Electric plant:		
In service	**$ 8,307,346**	$ 8,050,103
Less: Accumulated provision for depreciation	**(3,729,922)**	(3,615,375)
	4,577,424	4,434,728
Nuclear fuel, at amortized cost	**339,697**	341,012
Construction work in progress	**2,277,147**	2,212,224
	7,194,268	6,987,964
Investments and funds:		
Nuclear decommissioning trust fund	**355,832**	343,698
Investment in associated companies	**65,496**	66,437
Long-term investments	**83,689**	81,720
Restricted cash and investments	**96,432**	34,975
Other	**16,884**	16,098
	618,333	542,928
Current assets:		
Cash and cash equivalents	**312,206**	408,193
Restricted cash and short-term investments	**247,699**	272,686
Receivables	**134,573**	128,992
Inventories, at average cost	**263,795**	286,168
Prepayments and other current assets	**31,439**	16,894
	989,712	1,112,933
Deferred charges:		
Deferred debt expense, being amortized	**98,695**	57,175
Regulatory assets	**412,456**	331,108
Other	**51,786**	63,104
	562,937	451,387
	$ 9,365,250	$ 9,095,212

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

Oglethorpe Power Corporation
Condensed Balance Sheets (Unaudited)
September 30, 2014 and December 31, 2013

	(dollars in thousands)	
	2014	2013
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 765,361**	$ 714,489
Accumulated other comprehensive margin (deficit)	**160**	(549)
	765,521	713,940
Long-term debt	**6,881,522**	6,817,518
Obligation under capital leases	**102,280**	121,731
Other	**16,166**	15,379
	7,765,489	7,668,568
Current liabilities:		
Long-term debt and capital leases due within one year	**299,960**	152,153
Short-term borrowings	**264,624**	279,407
Accounts payable	**67,809**	101,529
Accrued interest	**52,837**	58,193
Member power bill prepayments, current	**100,430**	82,405
Other current liabilities	**45,354**	42,253
	831,014	715,940
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**21,047**	22,157
Asset retirement obligations	**426,212**	408,050
Member power bill prepayments, non-current	**71,819**	32,313
Power sale agreement, being amortized	**16,028**	26,107
Regulatory liabilities	**167,250**	158,789
Other	**66,391**	63,288
	768,747	710,704
	$9,365,250	$9,095,212

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 Nine Months Ended September 30, 2014 and 2013

	(dollars in thousands)			
	Three Months		Nine Months	
	2014	2013	**2014**	2013
Operating revenues:				
Sales to Members	**$338,740**	$315,646	**$1,011,615**	$908,490
Sales to non-Members	**30,665**	34,079	**81,073**	71,498
Total operating revenues	**369,405**	349,725	**1,092,688**	979,988
Operating expenses:				
Fuel	**147,314**	138,252	**413,566**	351,467
Production	**95,570**	88,689	**302,658**	272,703
Depreciation and amortization	**41,784**	40,779	**123,902**	116,440
Purchased power	**15,603**	12,989	**51,981**	40,373
Accretion	**6,198**	5,755	**18,324**	17,062
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(7,749)**	(7,005)	**(27,885)**	(25,672)
Total operating expenses	**298,720**	279,459	**882,546**	772,373
Operating margin	**70,685**	70,266	**210,142**	207,615
Other income:				
Investment income	**8,494**	8,353	**26,921**	23,778
Other	**1,956**	2,317	**6,565**	6,834
Total other income	**10,450**	10,670	**33,486**	30,612
Interest charges:				
Interest expense	**88,395**	80,569	**256,277**	232,597
Allowance for debt funds used during construction	**(25,921)**	(23,597)	**(76,035)**	(73,013)
Amortization of debt discount and expense	**4,208**	3,860	**12,514**	12,013
Net interest charges	**66,682**	60,832	**192,756**	171,597
Net margin	**$ 14,453**	$ 20,104	**$ 50,872**	$ 66,630

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 Nine Months Ended September 30, 2014 and 2013

	(dollars in thousands)			
	Three Months		Nine Months	
	2014	2013	**2014**	2013
Net margin	**$14,453**	$20,104	**$50,872**	$66,630
Other comprehensive margin:				
Unrealized gain (loss) on available-for-sale securities	**(118)**	205	**709**	(1,097)
Total comprehensive margin	**$14,335**	$20,309	**$51,581**	$65,533

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 Nine Months Ended September 30, 2014 and 2013

(dollars in thousands)

	Patronage Capital and Membership Fees	**Accumulated Other Comprehensive Margin (Deficit)**	**Total**
Balance at December 31, 2012	$673,009	$ 903	$673,912
Components of comprehensive margin:			
Net margin	66,630	—	66,630
Unrealized (loss) on available-for-sale securities	—	(1,097)	(1,097)
Balance at September 30, 2013	$739,639	$ (194)	$739,445
Balance at December 31, 2013	$714,489	$ (549)	$713,940
Components of comprehensive margin:			
Net margin	50,872	—	50,872
Unrealized gain on available-for-sale securities	—	709	709
Balance at September 30, 2014	**$765,361**	**$ 160**	**$765,521**

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

Oglethorpe Power Corporation
Condensed Statements of Cash Flows (Unaudited)
For the Nine Months Ended September 30, 2014 and 2013

	(dollars in thousands)	
	2014	2013
Cash flows from operating activities:		
Net margin	**$ 50,872**	$ 66,630
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**233,041**	218,425
Accretion cost	**18,324**	17,062
Amortization of deferred gains	**(1,341)**	(1,341)
Allowance for equity funds used during construction	**(968)**	(1,938)
Deferred outage costs	**(41,931)**	(33,347)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(27,885)**	(25,672)
Gain on sale of investments	**(13,384)**	(21,694)
Regulatory deferral of costs associated with nuclear decommissioning	**2,690**	10,652
Other	**11,967**	(5,416)
Change in operating assets and liabilities:		
Receivables	**(5,300)**	(2,995)
Inventories	**22,373**	(13,684)
Prepayments and other current assets	**(15,299)**	(234)
Accounts payable	**4,493**	(76,892)
Accrued interest	**(5,356)**	(9,292)
Accrued taxes	**4,628**	19,601
Other current liabilities	**(4,109)**	(4,264)
Member power bill prepayments	**57,531**	2,091
Total adjustments	**239,474**	71,062
Net cash provided by operating activities	**290,346**	137,692
Cash flows from investing activities:		
Property additions	**(428,585)**	(414,493)
Activity in decommissioning fund—Purchases	**(101,090)**	(479,622)
—Proceeds	**97,475**	475,446
Decrease (increase) in restricted cash and investments	**(61,457)**	(22,111)
Decrease (increase) in restricted cash and short-term investments	**24,987**	(190,184)
Activity in other long-term investments—Purchases	**(17,006)**	(34,510)
—Proceeds	**17,394**	36,753
Activity on interest rate options—Collateral returned	**(81,070)**	(146,730)
—Collateral received	**46,100**	168,840
Other	**(3,053)**	11,563
Net cash used in investing activities	**(506,305)**	(595,048)
Cash flows from financing activities:		
Long-term debt proceeds	**1,009,320**	875,640
Long-term debt payments	**(369,253)**	(313,983)
(Decrease) increase in short-term borrowings, net	**(479,783)**	34,332
Other	**(40,312)**	(559)
Net cash provided by financing activities	**119,972**	595,430
Net decrease in cash and cash equivalents	**(95,987)**	138,074
Cash and cash equivalents at beginning of period	**408,193**	298,565
Cash and cash equivalents at end of period	**$ 312,206**	$ 436,639
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 182,059**	$ 165,388
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	**$ (33,157)**	$ 19,488

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 Nine Months ended September 30, 2014 and 2013

(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 nine- month periods ended September 30, 2014 and 2013. 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, 2013, as filed with the SEC. The results of operations for the three- and nine- month periods ended September 30, 2014 are not necessarily indicative of results to be expected for the full year. As noted in our 2013 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 2013 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 September 30, 2014 and December 31, 2013.

		Fair Value Measurements at Reporting Date Using		
	September 30, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(dollars in thousands)		
Nuclear decommissioning trust funds:				
Domestic equity	**$151,485**	$151,485	$ —	$ —
International equity trust	**72,518**	—	72,518	—
Corporate bonds	**39,713**	—	39,713	—
US Treasury and government agency securities	**62,440**	62,440	—	—
Agency mortgage and asset backed securities	**16,736**	—	16,736	—
Other	**12,940**	12,940	—	—
Long-term investments:				
International equity trust	**11,166**	—	11,166	—
Corporate bonds	**6,558**	—	6,558	—
US Treasury and government agency securities	**13,933**	13,933	—	—
Agency mortgage and asset backed securities	**570**	—	570	—
Mutual funds	**51,045**	51,045	—	—
Other	**417**	417	—	—
Interest rate options	**13,110**	—	—	13,110(1)
Natural gas swaps	**(1,764)**	—	(1,764)	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2013	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	$143,929	$143,929	$ —	$ —
International equity trust	72,466	—	72,466	—
Corporate bonds	39,863	—	39,863	—
US Treasury and government agency securities	44,846	44,846	—	—
Agency mortgage and asset backed securities	30,133	—	30,133	—
Municipal Bonds	641	—	641	—
Other	11,820	11,820	—	—
Long-term investments:				
Corporate bonds	6,487	—	6,487	—
US Treasury and government agency securities	8,563	8,563	—	—
Agency mortgage and asset backed securities	3,679	—	3,679	—
International equity trust	11,148	—	11,148	—
Mutual funds	51,559	51,559	—	—
Other	284	284	—	—
Interest rate options	63,471	—	—	63,471[1]
Natural gas swaps	1,011	—	1,011	—

(1) Interest rate options as reflected on the unaudited condensed Balance Sheet include the fair value of the interest rate options offset by $0 and $34,970,000 of collateral received from the counterparties at September 30, 2014 and December 31, 2013, respectively.

The Level 2 investments above in corporate bonds and agency mortgage and asset backed securities may not be exchange traded. The fair value measurements for these investments are based on a market approach, including the use of observable inputs. Common inputs include reported trades and broker/dealer bid/ask prices. The fair value of the Level 2 investments above in international equity trust are calculated based on the net asset value per share of the fund. There are no unfunded commitments for the international equity trust and redemption may occur daily with a 3-day redemption notice period.

The following tables present the changes in Level 3 assets measured at fair value on a recurring basis during the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30, 2014
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at June 30, 2014	$18,535
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(5,425)
Balance at September 30, 2014	**$13,110**

	Three Months Ended September 30, 2013
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at June 30, 2013	$43,680
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(149)
Balance at September 30, 2013	$43,531

	Nine Months Ended September 30, 2014
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at December 31, 2013	$ 63,471
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(50,361)
Balance at September 30, 2014	**$ 13,110**

	Nine Months Ended September 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)	17,748
Balance at September 30, 2013	$43,531

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

The estimated fair values of our long-term debt, including current maturities at September 30, 2014 and December 31, 2013 were as follows (in thousands):

	2014		2013	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$7,157,870**	**$7,983,009**	$6,954,293	$7,317,476

The estimated fair value of long-term debt is classified as Level 2 and is estimated based on observed or quoted market prices for the same or similar issues or on current rates offered to us for debt of similar maturities. The primary sources of our long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank that is guaranteed by the Rural Utilities Service or the U.S. Department of Energy. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC) and by CoBank, ACB. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from third party investment banking firms and 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 September 30, 2014 plus an applicable spread, 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.

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. To hedge the risk of rising interest rates on long-term debt in connection with capital expenditures, we have entered into interest rate options. We do not apply hedge accounting for any of these derivatives, but apply regulatory accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps and interest rate options are reflected as regulatory assets or liabilities, as appropriate.

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

It is possible that volatility in commodity prices and/or interest rates could cause us to have credit risk exposures with one or more counterparties. We currently have credit risk exposure to our interest rate options counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of September 30, 2014, 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 our 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 September 30, 2014 and December 31, 2013, the fair value of our natural gas contracts were a net liability of approximately $1,764,000 and $1,011,000, respectively.

As of September 30, 2014 and December 31, 2013, neither we nor any counterparties were required to post credit support or collateral under these natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on September 30, 2014 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit in the amount of $2,022,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of September 30, 2014 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2014	0.4
2015	7.9
2016	5.4
Total	**14.3**

Interest rate options. We are exposed to the risk of rising interest rates when we incur long-term debt in connection with capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4. In the fourth quarter of 2011, we purchased LIBOR swaptions at a cost of $100,000,000 with a total notional amount of approximately $2,200,000,000 to hedge the interest rates on a portion of the debt that we are incurring to finance two additional nuclear units at Plant Vogtle. Since 2013, swaptions having a notional amount of approximately $1,174,248,000 have expired and as of September 30, 2014, the remaining notional amount of our outstanding swaptions was approximately $1,004,955,000.

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 average 107 basis points above the corresponding LIBOR swap rates that were in effect as of September 30, 2014 and the weighted average fixed rate is 4.08%. Swaptions having notional amounts totaling $419,796,000 expired without value during the nine months ended September 30, 2014. 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. At September 30, 2014 and December 31, 2013, the fair value of these swaptions was approximately $13,110,000 and $63,471,000, 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 September 30, 2014, and December 31, 2013, we held $0 and $34,970,000 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 $13,110,000 and $28,501,000 at September 30, 2014 and December 31, 2013, respectively.

We are deferring unrealized 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 realized 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.

The following table reflects the remaining notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of September 30, 2014.

Year	**LIBOR Swaption Notional Dollar Amount** (in thousands)
2014	$ 143,629
2015	470,624
2016	310,533
2017	80,169
Total	**$1,004,955**

The table below reflects the fair value of derivative instruments and their effect on our condensed balance sheets at September 30, 2014 and December 31, 2013.

	Balance Sheet Location	**Fair Value**	
		2014	2013
		(dollars in thousands)	
Not designated as hedges:			
Assets:			
Interest rate options(1)	Other deferred charges	**$13,110**	$63,471
Natural gas swaps	Other current assets	**$ 258**	$ 1,011
Liabilities:			
Natural gas swaps	Other current liabilities	**$ 2,022**	$ —

(1) Excludes liability associated with cash collateral of $0 and $34,970,000 as of September 30, 2014 and December 31, 2013, 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 nine months ended September 30, 2014 and 2013.

	Statement of Revenues and Expenses Location	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
		(dollars in thousands)			
Not Designated as hedges:					
Natural Gas Swaps	Fuel	**$ 638**	$ 122	**$1,874**	$ 688
Natural Gas Swaps	Fuel	**(889)**	(3,089)	**(890)**	(4,002)
		$(251)	$(2,967)	**$ 984**	$(3,314)

The following table presents the unrealized gains and (losses) on derivative instruments deferred on the balance sheet at September 30, 2014 and December 31, 2013.

	Balance Sheet Location	2014	2013
		(dollars in thousands)	
Not designated as hedges:			
Natural gas swaps	Regulatory liability	**$ —**	$ 1,011
Natural gas swaps	Regulatory asset	**$ (1,764)**	$ —
Interest rate options	Regulatory asset	**(47,598)**	(15,003)
		$(49,362)	$(13,992)

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.

	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)			
September 30, 2014				
Assets:				
Natural gas swaps	$ 261	$(2,025)	$ —	$(1,764)
Interest rate options	$13,110	$ —	$ —	$13,110
December 31, 2013				
Assets:				
Natural gas swaps	$ 1,069	$ (58)	$ —	$ 1,011
Interest rate options	$63,471	$ —	$(34,970)	$28,501

(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 funds are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning funds are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. As of September 30, 2014, approximately 79% 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 September 30, 2014 and December 31, 2013.

		Gross Unrealized		
		(dollars in thousands)		
September 30, 2014	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$196,523**	**$64,560**	**$ (2,185)**	**$258,898**
Debt	**166,710**	**9,159**	**(8,417)**	**167,452**
Other	**13,173**	**—**	**(2)**	**13,171**
Total	**$376,406**	**$73,719**	**$(10,604)**	**$439,521**

		Gross Unrealized		
		(dollars in thousands)		
December 31, 2013	Cost	Gains	Losses	Fair Value
Equity	$182,755	$68,424	$ (1,053)	$250,126
Debt	164,941	7,319	(9,070)	163,190
Other	12,101	2	—	12,103
Total	$359,797	$75,745	$(10,123)	$425,419

(E) *Recently Issued or Adopted Accounting Pronouncements.* In May 2014, the Financial Accounting Standards Board issued "Revenue from Contracts with Customers" (Topic 606). The new revenue standard requires that an entity recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The standard is effective for the annual reporting period beginning after December 15, 2016 and early adoption is not permitted. We are currently evaluating the future impact of this standard to our consolidated financial position or results of operations.

(F) *Accumulated Comprehensive Margin (Deficit).* 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 (Deficit). 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 2013 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 (Deficit) Three Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at June 30, 2013	$ (399)
Unrealized gain	181
Loss reclassified to net margin	24
Balance at September 30, 2013	$ (194)
Balance at June 30, 2014	$ 278
Unrealized (loss)	(100)
(Gain) reclassified to net margin	(18)
Balance at September 30, 2014	**$ 160**

	Nine Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at December 31, 2012	$ 903
Unrealized (loss)	(1,041)
(Gain) reclassified to net margin	(56)
Balance at September 30, 2013	$ (194)
Balance at December 31, 2013	$ (549)
Unrealized gain	782
(Gain) reclassified to net margin	(73)
Balance at September 30, 2014	**$ 160**

(G) *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.

a. Nuclear Construction

In April 2008, Georgia Power Company, acting for itself and as agent for us, 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 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 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.

Current 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 agreement. 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. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that proper venue is the U.S. District Court for the Southern District of Georgia. In September 2013, the Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia.

The portion of the additional costs claimed by the Contractor in its initial complaint that would be attributable to us, based on our ownership interest, was approximately $280 million in 2008 dollars with respect to these issues. The Contractor has also asserted that it is entitled to further schedule extensions. On May 22, 2014, the Contractor filed an amended counterclaim to the lawsuit pending in the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the Nuclear Regulatory Commission have delayed module production and the impacts to the Contractor are recoverable by the Contractor under the agreement and (ii) the changes to the basemat rebar design required by the Nuclear Regulatory Commission caused additional costs and delays recoverable by the Contractor under the agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations, but the Contractor subsequently asserted and may from time to time continue to assert that it is entitled to additional payments with respect to these new allegations, any of which could be substantial. 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.

While litigation is ongoing and Georgia Power and the Co-owners intend to vigorously defend their positions, Georgia Power and the Co-owners also 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 September 30, 2014, 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.

b. Patronage Capital Litigation

On March 13, 2014, a lawsuit was filed in the Superior Court of DeKalb County, Georgia, against us, Georgia Transmission and three of our member distribution cooperatives. Plaintiffs filed an amended complaint on July 28, 2014. The amended complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives and seeks to certify a defendant class of all but one of our 38 members. It was filed by four former consumer-members of four of our members on behalf of themselves and a proposed class of all former consumer-members of our members. Plaintiffs claim that approximately 30% of all the defendants' total allocated patronage capital belongs to former consumer-members. Plaintiffs also allege that patronage capital owed to former consumer-members includes patronage capital allocated by us to our members but not yet distributed to our members. Plaintiffs claim that the patronage capital of former consumer-members held by defendants and the proposed defendant class should be retired immediately when the consumer-members end their membership by terminating service, or alternatively, according to a revolving schedule of no longer than 13 years from the date of its allocation and seek relief to effect such retirements. Plaintiffs further seek to require the defendants to adjust rates in order to establish and maintain reasonable reserves to fund patronage capital retirements on this basis. Plaintiffs also claim that defendants and the proposed defendant class should be required to adopt policies to periodically retire the patronage capital of all consumer-members on a revolving schedule of no longer than 13 years from the date of its allocation. Our first mortgage indenture restricts our ability to distribute patronage capital. See "Item 1—BUSINESS—OGLETHORPE POWER CORPORATION—First Mortgage Indenture" in our 2013 Form 10-K. Although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level sufficient so that we could comply with the current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiffs' demands would be significant for a period of years.

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

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

c. Environmental Matters

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

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

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

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

(H) *Restricted Cash and Investments.* At September 30, 2014 and December 31, 2013, we had restricted cash and investments totaling $344,131,000 and $307,661,000, respectively, of which $96,432,000 and $34,975,000, respectively, was classified as long-term. Restricted cash balances consist primarily of funds posted as collateral by counterparties to our interest rate options. Restricted investments represent funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted investments will be utilized for future Rural Utilities Service Federal Financing Bank debt service payments. The funds on deposit earn interest at a rate of 5% per annum.

(I) *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 unaudited condensed balance sheet as of September 30, 2014 and December 31, 2013.

	2014	2013
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt[(a)]	**$ 74,415**	$ 82,499
Amortization on capital leases[(b)]	**11,897**	16,124
Outage costs[(c)]	**44,911**	35,155
Interest rate swap termination fees[(d)]	**10,343**	13,336
Depreciation expense[(f)]	**47,294**	48,362
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs[(g)]	**31,126**	27,678
Interest rate options cost[(h)]	**89,781**	38,984
Deferral of effects on net margin—Smith Energy Facility[(i)]	**96,811**	63,491
Other regulatory assets[(j)]	**5,878**	5,479
Total Regulatory Assets	**$412,456**	$331,108
Regulatory Liabilities:		
Accumulated retirement costs for other obligations[(e)]	**$ 21,069**	$ 24,520
Deferral of effects on net margin—Hawk Road Energy Facility[(i)]	**28,605**	23,379
Major maintenance reserve[(k)]	**26,762**	28,064
Deferred debt service adder[(l)]	**64,375**	57,223
Asset retirement obligations[(e)]	**21,508**	19,508
Other regulatory liabilities[(j)]	**4,931**	6,095
Total Regulatory Liabilities	**$167,250**	$158,789
Net Regulatory Assets	**$245,206**	$172,319

(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 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 maintenance and nuclear refueling outage costs. Coal-fired outage costs 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 swap 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 certain borrowings related to Vogtle Units No. 3 and No. 4 construction. Amortization will commence in February 2020 and will be amortized through February 2044, the life of the DOE-guaranteed loan which is financing a portion of the construction project.

(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 35 years and the amortization period of other regulatory liabilities range up to 18 years.

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

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

(J) *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 January 2018, with the majority of the balance scheduled to be credited by the end of 2015.

(K) *Debt.*

a) *Department of Energy Loan Guarantee:*

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (the "Title XVII Loan Guarantee Program"), we and the U.S. Department of Energy, acting by and through the Secretary of Energy entered into a Loan Guarantee Agreement on February 20, 2014 (the "Loan Guarantee Agreement") pursuant to which the Department of Energy agreed to guarantee our obligations (the "Department of Energy Guarantee") under the Note Purchase Agreement dated as of February 20, 2014 (the "Note Purchase Agreement"), among us, the Federal Financing Bank and the Department of Energy and the Future Advance Promissory Note No. 1 and the Future Advance Promissory Note No. 2, each dated February 20, 2014, made by us to Federal Financing Bank (the "Federal Financing Bank Notes" and together with the Note Purchase Agreement, the "FFB Credit Facility Documents"). The FFB Credit Facility Documents provide for a multi-advance term loan facility (the "Facility"), under which we may make term loan borrowings through Federal Financing Bank.

Proceeds of advances made under the Facility will be used to reimburse us for a portion of certain costs of construction relating to Vogtle Units No. 3 and No. 4 that are eligible for financing under the Title XVII Loan Guarantee Program ("Eligible Project Costs"). Aggregate borrowings under the Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) $3,057,069,461, $335,471,604 of which is designated for capitalized interest.

Under the Loan Guarantee Agreement, we are obligated to reimburse the Department of Energy in the event the Department of Energy is required to make any payments to the Federal Financing Bank under the Department of Energy Guarantee. Our payment obligations to the Federal Financing Bank under the Federal Financing Bank Notes and reimbursement obligations to the Department of Energy under the related reimbursement notes are secured equally and ratably with all of our other notes and obligations issued under our first mortgage indenture by a lien on substantially all of our owned tangible and certain of our intangible assets, including property we acquire in the future.

Advances. Advances may be requested under the Facility on a quarterly basis through December 31, 2020. On February 20, 2014, we made an initial borrowing in the principal amount of $725,000,000 at a fixed interest rate of 3.867% through February 20, 2044. In connection with the receipt of these funds, we repaid a like amount of outstanding short-term obligations, which included a $260,000,000 term loan originally due April 1, 2014 and $465,000,000 of commercial paper. These outstanding obligations were classified as long-term at December 31, 2013.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, accuracy of project-related representations and warranties, delivery of updated project-related information, certification regarding Georgia Power's compliance with certain obligations relating to the Cargo Preference Act, as amended, evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act, as amended, and certification from Department of Energy's consulting engineer that proceeds of the advance are used to reimburse Eligible Project Costs.

Maturity, Interest Rate and Amortization. The final maturity date for each advance under the Facility is February 20, 2044. Interest is payable quarterly in arrears on February 20, May 20, August 20 and November 20 of each year. Principal and interest payments will begin on February 20, 2020. Interest accrued and payable through November 20, 2019, up to a maximum of $335,471,604, is reflected as additional borrowings under the Facility. As of September 30, 2014, $17,179,000 of interest is reflected as long-term debt on our condensed balance sheet.

Under Future Advance Promissory Note No. 1, we may select an interest rate period applicable to each advance, with such interest rate periods ranging from three months to the final maturity date. All advances under Future Advance Promissory Note No. 2 will bear a fixed rate of interest through the final maturity date. Under both Federal Financing Bank Notes, the interest rates during the applicable interest rate periods will equal the current average yield on U.S. Treasuries of comparable maturity at the beginning of the interest rate period, plus a spread equal to 0.375%.

In connection with our entry into the Loan Guarantee Agreement and the FFB Credit Facility Documents, we incurred issuance costs of approximately $51,000,000, which will be amortized over the life of the borrowings under the Facility. Issuance costs include fees paid to the Department of Energy, legal and consulting expenses and costs for compliance with certain federal requirements (including compliance with the Davis-Bacon Act).

b) *Rural Utilities Service Guaranteed Loans:*

For the nine month period ended September 30, 2014, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $35,900,000 for general and environmental improvements at existing plants.

c) *Bond Issuance:*

On June 12, 2014, we issued $250,000,000 of 4.55% first mortgage bonds, Series 2014A primarily for the purpose of repaying outstanding commercial paper issued for the interim financing of general and environmental capital expenditures at our existing generation facilities and for general corporate purposes. The bonds are secured under our first mortgage indenture.

(L) *Purchase Agreements.* On April 11, 2014, we signed a precedent agreement with Transcontinental Gas Pipeline Company, LLC (Transco) for additional firm natural gas transportation to our Smith facility. The additional firm transportation is contingent upon the construction of a new natural gas pipeline by Transco. The agreement has a base term of 25 years, with a fixed charge of $37,700,000 per year for the base term. Our obligation to make payments begins when the pipeline expansion project is placed into service, which is projected to be May 1, 2017.

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 Nine Months Ended September 30, 2014 and 2013

Net Margin

Our net margin for the three-month and nine-month periods ended September 30, 2014 was $14.5 million and $50.9 million, respectively, compared to $20.1 million and $66.6 million for the same periods of 2013. Through September 30, 2014, we collected approximately 109% of our targeted net margin of $46.6 million for the year ending December 31, 2014. This is typical as our capacity revenues are recorded evenly throughout the year and our management generally budgets conservatively. We anticipate our board of directors 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. For additional information regarding our net margins requirements and policy, see "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Summary of Cooperative Operations—*Margins*" of our 2013 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.

Sales to Members. Total revenues from sales to members increased 7.3% and 11.4% in the three-month and nine-month periods ended September 30, 2014 compared to the same periods of 2013. Megawatt-hour sales to members increased 2.9% and 9.5% for the three-month and nine-month periods ended September 30, 2014 compared to the same periods of 2013. The average total revenue per megawatt-hour from sales to members increased 4.3% and 1.7% for the three-month and nine-month periods ended September 30, 2014 compared to the same periods of 2013. The increase in revenues from sales to members and in megawatt-hour sales to members in the nine-months ended September 30, 2014 versus the same period of 2013 was driven partly by increased generation at Plant Scherer due to increased member demand and partly due to increased generation at Plant Wansley Unit due to extensive testing of Mercury Air Toxic Standards environmental controls that were installed in early 2014. Increased member demand due to extreme cold weather during the winter of 2014 also contributed to the increase in sales to members for the nine-month period ended September 30, 2014.

The components of member revenues for the three-month and nine-month periods ended September 30, 2014 and 2013 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	**2014**	2013
Capacity revenues	**$ 188,750**	$ 182,107	**$ 570,502**	$ 547,482
Energy revenues	**149,990**	133,539	**441,113**	361,008
Total	**$ 338,740**	$ 315,646	**$ 1,011,615**	$ 908,490
Kilowatt-hours sold to members	**5,360,623**	5,210,893	**15,440,120**	14,097,380
Cents per kilowatt-hour	**6.32¢**	6.06¢	**6.55¢**	6.44¢

Capacity revenues from members increased 3.6% and 4.2% for the three-month and nine-month periods ended September 30, 2014 compared to the same periods of 2013. Capacity revenues are the revenues we receive for electric service whether or not our generation and purchased power resources are dispatched to produce electricity and are designed to cover the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges, plus a targeted margin. Each member is required to pay us for capacity furnished under its wholesale power contract according to the individual fixed percentage capacity cost responsibility for each resource in which it participates. 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.

Energy revenues were 12.3% and 22.2% higher for the three-month and nine-month periods ended September 30, 2014 compared to the same periods of 2013. Our average energy revenue per megawatt-hour from sales to members increased 9.2% and 11.6% for the three-month and nine-month periods ended September 30, 2014 as compared to the same periods of 2013. The increase in energy revenues for the three-month period ended September 30, 2014 as compared to the same period of 2013 was primarily due to an increase in higher cost natural gas generation, primarily from our combustion turbine facilities. The increase in energy revenues for the comparable nine-month period ended September 30, 2014 as compared to the same period of 2013 was partly due to an increase in higher cost coal-fired generation and to a change in the mix of our natural gas generation with an increase in generation from our higher cost combustion turbine facilities. Increased generation during the winter of 2014 as a result of extreme cold weather also contributed to this increase. 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 nine-month periods ended September 30, 2014 decreased 10.0% and increased 13.4% as compared to the same periods of 2013. The decrease in the third quarter of 2014 compared to the same period of 2013 was primarily due to lower energy sales from the Smith Energy Facility. The increase for non-member sales year-to-date in 2014 was primarily due to sales of natural gas of $10.8 million during the first quarter of 2014.

Operating Expenses

Operating expenses for the three-month and nine-month periods ended September 30, 2014 increased 6.9% and 14.3% as compared to the same periods of 2013. These increases were due to higher fuel costs, production costs and depreciation and amortization expenses as compared to the same periods of 2013.

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

Fuel Source	Three Months Ended September 30, 2014 Cost (thousands)	2014 Generation (MWh)	2014 Cost per MWh	2013 Cost (thousands)	2013 Generation (MWh)	2013 Cost per MWh
Coal	**$ 54,863**	**1,800,149**	**$30.48**	$ 53,934	1,818,076	$29.67
Nuclear	**20,824**	**2,694,182**	**7.73**	23,238	2,636,084	8.82
Gas:						
Combined Cycle	**57,756**	**1,690,619**	**34.16**	55,665	1,700,112	32.74
Combustion Turbine	**13,871**	**234,819**	**59.07**	5,415	72,358	74.84
	$147,314	**6,419,769**	**$22.95**	$138,252	6,226,630	$22.20

Fuel Source	Nine Months Ended September 30, 2014 Cost (thousands)	2014 Generation (Mwh)	2014 Cost per MWh	2013 Cost (thousands)	2013 Generation (Mwh)	2013 Cost per MWh
Coal	**$175,011**	**5,713,709**	**$30.63**	$139,746	4,792,309	$29.16
Nuclear	**63,591**	**7,497,391**	**8.48**	64,168	7,295,446	8.80
Gas:						
Combined Cycle	**150,337**	**3,855,072**	**39.00**	137,335	4,119,313	33.34
Combustion Turbine	**24,627**	**353,585**	**69.65**	10,218	136,690	74.75
	$413,566	**17,419,757**	**$23.74**	$351,467	16,343,758	$21.50

For the three-month and nine-month periods ended September 30, 2014, total fuel costs increased 6.6% and 17.7% and megawatt-hour generation increased 3.1% and 6.6%, respectively, compared to the same periods of 2013. Average fuel costs per megawatt-hour increased 3.3% and 10.4% in the three-month and nine-month periods ended September 30, 2014 compared to the same periods of 2013. The increase in total fuel costs was primarily due to higher generation from our coal-fired plants. As discussed above, extensive testing of environmental equipment at Plant Wansley increased generation in 2014 by 351,000 megawatt-hours for the nine-month period ended September 30, 2014 as compared to the same period of 2013 when it was in reserve shutdown for most of the nine month period primarily due to more economical generation from natural gas-fired facilities. Generation from Plant Scherer also increased 12.6% during the nine-month period ended September 30, 2014 as compared to the same period of 2013 due to increased demand from our members. The extreme cold weather in the first quarter of 2014 also contributed to the increase in megawatt-hours of generation for the nine month period ended September 30, 2014.

Production costs increased 7.8% and 11.0% for the three-month and nine-month periods ended September 30, 2014 as compared to the same periods of 2013. The increase in the third quarter of 2014 versus the same period of 2013 resulted primarily from higher operations and maintenance expenses at our co-owned facilities. Increased environmental expenses at our coal-fired plants also contributed to the increase. The increase for the nine-month period ended September 30, 2014 as compared to the same period of 2013 resulted primarily from (i) the cost of natural gas sold to non-members of $6 million, (ii) higher operations and maintenance costs at our co-owned facilities and (iii) environmental expenses at our coal-fired plants.

Depreciation and amortization costs increased 2.5% and 6.4% for the three-month and nine-month periods ended September 30, 2014 as compared to the same periods of 2013. The increase in depreciation expense in 2014 was primarily due to $291 million of environmental capital improvements at Plant Scherer that were primarily placed into service in May and August of 2013.

Interest charges

Interest expense increased 9.7% and 10.2% for the three-month and nine-month periods ended September 30, 2014 as compared to the same periods of 2013 primarily due to increased debt to finance construction of Vogtle Units No. 3 and No. 4.

Financial Condition

Balance Sheet Analysis as of September 30, 2014

Assets

Cash used for property additions for the nine-month period ended September 30, 2014 totaled $428.6 million. Of this amount, approximately $250 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, $25 million for environmental control systems being installed primarily at Plant Scherer and $47 million for nuclear fuel purchases. The remaining expenditures were for normal additions and replacements to existing generation facilities.

Long-term restricted cash and investments at September 30, 2014 consist primarily of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. 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. At December 31, 2013, the balance represented restricted cash posted as collateral by counterparties to our interest rate options.

Deferred debt expense, being amortized increased $41.5 million for the nine months ended September 30, 2014 due to debt related costs associated with a $3.057 billion loan with the Department of Energy, which closed in February 2014. For additional information regarding this loan, see Note K.

Regulatory assets increased $81.3 million for the nine months ended September 30, 2014. The increase was primarily due to a $50.8 million increase in the deferral of unrealized losses on, and expirations of, our interest rate options. For information regarding our interest rate options, see Note C. In addition, there was a $33.3 million increase in deferred losses related to Smith Energy Facility. The effects on net margin for Smith are being deferred until the end of 2015 at which time the amounts will be amortized over the remaining life of the facility. For additional information regarding all regulatory assets, see Note I.

Equity and Liabilities

Accounts payable decreased $33.7 million for the nine-month period ended September 30, 2014 as a result of $38.4 million in credits applied to the members' bills in the first quarter of 2014 for a board approved reduction to 2013 revenue requirements as a result of margins collected in excess of our 2013 target. Offsetting the decrease was a $7.2 million increase in natural gas purchases.

Member power bill prepayments represent funds received from the members for the prepayment of their monthly power bills. At September 30, 2014, $100.4 million of member power bill prepayments was classified as a current liability and $71.8 million was classified as a long-term liability. During the nine-month period ended September 30, 2014, $97.7 million of prepayments were received from the members and $40.2 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note J.

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4.

We are participating in 30% of the cost of constructing two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. As of September 30, 2014, our total investment in the additional Vogtle units was $2.3 billion.

In April 2008, Georgia Power, for itself and as agent for us, the Municipal Electric Authority of Georgia and the City of Dalton, the "Co-owners," signed an Engineering, Procurement and Construction Contract with Westinghouse Electric Company, LLC and Stone & Webster, Inc., together, the "Contractor." Pursuant to the contract, the Contractor will supply and construct two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology, with the exception of certain owner supplied items. Under the contract, the Co-owners will pay a purchase price that is subject to certain price escalation and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders and performance bonuses. Each Co-owner is severally, not jointly, liable to the Contractor based on its ownership share. The contract includes certain liquidated damages upon the Contractor's failure to comply with schedule and performance guarantees. The Contractor's liability for those liquidated damages and for warranty claims is subject to a cap.

The obligations of Westinghouse and Stone & Webster are guaranteed by their parent companies Toshiba Corporation and The Shaw Group, Inc., a subsidiary of Chicago Bridge & Iron Co. N.V., respectively. In the event of certain credit rating downgrades of any Co-owner, that Co-owner would be required to provide a letter of credit or other credit enhancement to the Contractor. In addition, the Co-owners may terminate the contract at any time for their convenience, provided that the Co-owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may terminate the contract under certain circumstances, including certain Co-owner suspension or delays of work, action by a governmental authority to stop work permanently, certain breaches of the contract by the Co-owners, Co-owner insolvency and certain other events. As agent for the Co-owners, Georgia Power has designated Southern Nuclear Operating Company as its agent for contract management.

The Nuclear Regulatory Commission certified the Westinghouse AP1000 Design Control Document (DCD) effective December 30, 2011. On February 10, 2012, the Nuclear Regulatory Commission issued combined licenses for Vogtle Units No. 3 and No. 4 which allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state level, and additional challenges are expected as construction proceeds.

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.

Current litigation relates to costs associated with design changes to the 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. 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. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that proper venue is the U.S. District Court for the Southern District of Georgia. In September 2013, the Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia.

The portion of the additional costs claimed by the Contractor that would be attributable to us, based on our ownership interest, is approximately $280 million in 2008 dollars with respect to these issues. The Contractor has also asserted that it is entitled to further schedule extensions. On May 22, 2014, the Contractor filed an amended counterclaim to the lawsuit pending in the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the Nuclear Regulatory Commission have delayed module production and the impacts to the Contractor are recoverable by the Contractor under the agreement and (ii) the changes to the basemat rebar design required by the Nuclear Regulatory Commission caused additional costs and delays recoverable by the Contractor under the agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations, but the Contractor subsequently asserted and may from time to time continue to assert that it is entitled to additional payments with respect to these new allegations, any of which could be substantial. 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.

While litigation has commenced and Georgia Power and the Co-owners intend to vigorously defend their positions, Georgia Power and the Co-owners also 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.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the combined licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the Nuclear Regulatory Commission.

Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners, the Contractor, or both.

The issues mentioned above, in addition to other factors that have materialized during the development and construction process, have caused revisions to the estimated project schedule and cost. The current estimated commercial operation dates for Units No. 3 and No. 4 are the fourth quarter of 2017 and 2018, respectively. Our current estimated project cost, including allowance for funds used during construction and a contingency amount, is approximately $4.5 billion. Commercial responsibility for the revised commercial operation dates and additional costs remain in dispute.

As construction continues, the risk remains that ongoing challenges with contractor performance including additional challenges in the fabrication, assembly, delivery and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Vogtle Units No. 3 and No. 4, or other issues could arise and may further impact project schedule and cost. Contractor performance and progress in recent months has resulted in additional schedule pressure. The Co-owners expect the Contractor to employ mitigation efforts to maintain the current project schedule and believe the terms of the contract provide that the Contractor is responsible for any related costs.

Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the contract, but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time. See "RISK FACTORS" for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units. For additional information regarding Vogtle Units No. 3 and No. 4, see "*—Financing Activities—Department of Energy-Guaranteed Loan*" and Notes G and K.

Environmental Regulations

The U.S. Environmental Protection Agency, or EPA, continues to develop a number of rules that significantly expand the scope of regulation of air emissions, water and waste management at power plants. Following are some of the recent developments that may affect future operations at our facilities.

On June 18, 2014, EPA proposed a rule for new source performance standards at certain existing power plants called the "Clean Power Plan." As proposed, the rule would cut carbon dioxide emissions from existing fossil fuel-fired power plants nationwide by an average of 30% from 2005 levels by 2030, with an additional interim goal for the years 2020 through 2029. For Georgia, however, the proposal would require a 44% reduction in emission rates from 2012 levels through a combination of plant efficiency improvements, shifting generation from coal-fired plants to natural gas-fired plants, addition of renewable and other non-carbon emitting generation (e.g. nuclear), and implementing various demand reducing energy efficiency measures. That same day, EPA also proposed new source performance standards for certain modified or reconstructed fossil fuel-fired power plants which, if finalized, could apply to our coal-fired and natural gas-fired facilities. EPA is scheduled to finalize the Clean Power Plan as well as the standards for modified or reconstructed sources by June 1, 2015.

On October 28, 2014, EPA issued a Notice of Data Availability (NODA) related to the Clean Power Plan, which was not intended to revise EPA's proposal but to provide an opportunity for the public to comment on some additional technical details. We commented on the proposed standards for modified and reconstructed sources and are in the process of developing comments on the Clean Power Plan and the NODA, which will include preliminary analysis of cost to us and our members, and intend to provide them to the publically available comment docket before the December 1, 2014 deadline. If finalized as proposed, the Clean Power Plan could result in operational restrictions and compliance costs which could be significant. We believe that some of the policy approaches being proposed could have significant negative consequences for both the economy and electric systems of Georgia and nationwide. However, the outcome of the Clean Power Plan and the standards for modified or reconstructed sources rulemakings, including any subsequent challenges, cannot be determined at this time and will depend on numerous factors such as: how the State of Georgia chooses to implement the final requirements; the schedules for implementation and compliance; how new and existing nuclear generation is treated in the final rule; the impacts of future decisions regarding unit retirement and replacement (including the type and amount of any replacement capacity); the availability and cost of additional natural gas supplies, the changes that may be needed in the transmission system to accommodate new, potentially intermittent generation sources; and the availability and cost of technologies to improve the efficiency of the existing coal-fired units.

On February 12, 2013, EPA proposed a rule that would require many states, including Georgia, to revise those portions of their State Implementation Plans (SIPs) that relate to the regulation of excess emissions at industrial facilities, including fossil fuel-fired electric generating units, during periods of startup, shut-down or malfunction (SSM). EPA's proposed determination, if finalized, would require revisions to all affected SIPs within 18 months. Since that time, in litigation over this rulemaking, EPA has delayed final action on the proposal until May 22, 2015, which would delay the SIP submission deadline for each of the states subject to the rule until November 2016. On September 17, 2014 EPA proposed supplemental changes to its February 2013 proposal, proposing that affected states like Georgia must remove all affirmative defense provisions in their SIPs as a condition of complying with the proposed SSM SIP call. If finalized as proposed, these new rules could result in additional compliance and operational costs at our power plants. We cannot predict the ultimate outcome of this rulemaking and any ensuing litigation regarding it that may occur.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts on fish and other aquatic life. EPA's final section 316(b) requirements for existing power plants and manufacturing facilities were published in the August 15, 2014 *Federal Register*, making them effective October 14, 2014. The final rule applies to all existing facilities that withdraw at least two million gallons of water per day and that use at least 25% of such water exclusively for cooling purposes. We are in the process now of conferring with the Georgia Environmental Protection Division to determine what modifications, if any, need to be made to our four co-owned power plants that trigger the cooling water use threshold (Plants Scherer, Wansley, Vogtle and Hatch) to meet the new finalized standards. Capital requirements for any additional controls that might be needed for compliance at any of these plants cannot be determined at this time, but are not expected to be significant, and the result of any litigation which has been brought challenging the final rules cannot be predicted.

On April 29, 2014, the U. S. Supreme Court upheld the Cross State Air Pollution Rule (CSAPR), reversing a 2012 decision of the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit which had invalidated the CSAPR. The Supreme Court remanded the case back to the D.C. Circuit for further proceedings consistent with the decision. On October 23, 2014, the D.C. Circuit issued an order lifting its previously-issued stay of CSAPR, which may lead to the implementation of the rule, delayed by three years due to the litigation. Therefore, CSAPR's Phase 1 emission budgets may begin on January 1, 2015, for the annual programs and May 1, 2015, for the ozone-season NO_x program, while CSAPR's Phase 2 emission budgets would apply beginning in 2017. Briefing on the remaining issues in the litigation is underway, and we cannot predict the outcome of that litigation or the effect, if any, it may have on CSAPR or the future operations of our co-owned units at Plants Scherer and Wansley. Given the recent installation of additional pollution control equipment at Plant Scherer, we do not anticipate the need to purchase allowances for the operation of our units at either facility to comply with CSAPR.

For further discussion regarding potential effects on our business from environmental regulations, including potential capital requirements, see "Item 2—Management's Discussion and Analysis of Financial Condition and Results of Operations—Financial Condition—Capital Requirements and Liquidity and Sources of Capital—*Environmental Regulations*" in our quarterly reports on Form 10-Q for the quarterly periods ended March 31, 2014 and June 30, 2014, as well as "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 2013 Form 10-K.

Liquidity

At September 30, 2014, we had $1.6 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $312 million in cash and cash equivalents and $1.3 billion of unused and available committed credit arrangements.

At September 30, 2014, we had in excess of $1.8 billion of committed credit arrangements in place and $1.3 billion available under these facilities. These five separate facilities are reflected in the table below:

Committed Credit Facilities			
	Authorized Amount	**Available September 30, 2014**	**Expiration Date**
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit led by Bank of America[1]	$1,265	$865[2]	June 2015
CFC Line of Credit	110	110	September 2016
CFC Line of Credit[3]	210	210	December 2018
JPMorgan Chase Line of Credit	150	34[4]	December 2018
Secured Facilities:			
CFC Term Loan[3]	250	250	December 2018

(1) We plan to renew this facility in the first quarter of 2015.

(2) Of the portion of this facility that was unavailable at September 30, 2014, $264.6 million was dedicated to support outstanding commercial paper and $135.5 million was related to letters of credit issued to support variable rate demand bonds.

(3) Any amounts drawn under the $210 million unsecured line of credit with CFC will reduce the amount that can be drawn under the $250 million secured term loan. Any amounts borrowed under the $250 million term loan would be secured under our first mortgage indenture, with a maturity no later than December 31, 2043.

(4) Of the portion of this facility that was unavailable at September 30, 2014, $113.7 million related to letters of credit issued to support variable rate demand bonds and $2.2 million related to letters of credit issued to post collateral to third parties.

As of September 30, 2014, we were using our commercial paper program to provide interim funding for 1) the monthly payments related to the construction of Vogtle Units No. 3 and No. 4 prior to receiving advances of permanent funding under the Department of Energy-guaranteed Federal Financing Bank loan, which can be requested no more frequently than quarterly and 2) the premium payments made in connection with our interest rate hedging program. Between our credit arrangements and projected cash on hand, we believe we have sufficient liquidity to cover our normal operations and to provide for the interim financings described above.

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 $970 million in the aggregate, of which $719 million remained available at September 30, 2014. 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.

Several of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At September 30, 2014, the required minimum level was $675 million and our actual patronage capital was $765 million. Additional covenants contained in several of our credit facilities limit our secured indebtedness and unsecured indebtedness, both as defined in the credit agreements, to $12.0 billion and $4.0 billion, respectively. At September 30, 2014, we had $7.3 billion of secured indebtedness and $265 million of unsecured indebtedness outstanding, which was well within the covenant thresholds.

At September 30, 2014, we had $344 million on deposit in the Rural Utilities Service Cushion of Credit Account, all of which is classified as a restricted investment. See "—Balance Sheet Analysis as of September 30, 2014—*Assets*" for more information regarding this account.

Financing Activities

First Mortgage Indenture. At September 30, 2014, we had $7.2 billion of long-term debt outstanding 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. See "Item 1—BUSINESS—OGLETHORPE POWER CORPORATION—First Mortgage Indenture" in our 2013 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. We currently have three approved Rural Utilities Service-guaranteed loans, totaling $561 million, which are being funded through the Federal Financing Bank and are in various stages of being drawn down, with $339 million remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture.

Department of Energy-Guaranteed Loan. In February 2014, we closed on a loan with the Department of Energy that will fund up to the lesser of $3.057 billion or 70% of eligible project costs related to the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. This loan is being funded by the Federal Financing Bank and is backed by a federal loan guarantee provided by the Department of Energy.

As of September 30, 2014, our total investment in Vogtle Units No. 3 and No. 4 was $2.3 billion and we have incurred $2.1 billion of debt to provide long-term financing for this investment. This long-term debt includes $1.4 billion of taxable first mortgage bonds we previously issued and $742 million, including capitalized interest, under the Department of Energy loan facility. The facility may be used until no later than December 2020 to provide long-term funding for up to 70% of eligible project costs after they are incurred. As of September 30, 2014, we have the capacity to fund an additional $775 million under the facility based on the amount of eligible project costs we have incurred to date. We anticipate making draws on at least a semi-annual basis to meet our funding requirements as construction progresses. When advanced, the debt will be secured under our first mortgage indenture. For additional information regarding this loan, see Note K.

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 2013 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

There have not been any material changes to market risks from those reported in "Item 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK" of our 2013 Form 10-K.

Item 4. Controls and Procedures

As of September 30, 2014, 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 September 30, 2014 that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

The ultimate outcome of pending or potential litigation against us cannot be predicted at this time; however, we do not anticipate that the ultimate liabilities, if any, arising from such proceedings would have a material effect on our financial condition or results of operations.

Patronage Capital Litigation

On March 13, 2014, a lawsuit was filed in the Superior Court of DeKalb County, Georgia, against us, Georgia Transmission and three of our member distribution cooperatives. Plaintiffs filed an amended complaint on July 28, 2014. The amended complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives and seeks to certify a defendant class of all but one of our 38 members. It was filed by four former consumer-members of four of our members on behalf of themselves and a proposed class of all former consumer-members of our members. Plaintiffs claim that approximately 30% of all the defendants' total allocated patronage capital belongs to former consumer-members. Plaintiffs also allege that patronage capital owed to former consumer-members includes patronage capital allocated by us to our members but not yet distributed to our members. Plaintiffs claim that the patronage capital of former consumer-members held by defendants and the proposed defendant class should be retired immediately when the consumer-members end their membership by terminating service, or alternatively, according to a revolving schedule of no longer than 13 years from the date of its allocation and seek relief to effect such retirements. Plaintiffs further seek to require the defendants to adjust rates in order to establish and maintain reasonable reserves to fund patronage capital retirements on this basis. Plaintiffs also claim that defendants and the proposed defendant class should be required to adopt policies to periodically retire the patronage capital of all consumer-members on a revolving schedule of no longer than 13 years from the date of its allocation. Our first mortgage indenture restricts our ability to distribute patronage capital. See "Item 1—BUSINESS—OGLETHORPE POWER CORPORATION—First Mortgage Indenture" in our 2013 Form 10-K. Although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level sufficient so that we could comply with the current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiffs' demands would be significant for a period of years.

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

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

Vogtle Units No. 3 and No. 4

For a discussion of litigation related to the development and construction of Vogtle Units No. 3 and No. 4, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—Capital Requirements and Liquidity and Sources of Capital—*Vogtle Units No. 3 and No. 4*."

Item 1A. Risk Factors

There have been no material changes from the risks disclosed in "Item 1A—RISK FACTORS" of our 2013 Form 10-K and "Item 1A—Risk Factors" of our quarterly report for the quarterly period ended June 30, 2014.

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

Number	Description
4.1	Ninth Amended and Restated Loan Contract, dated as of September 2, 2014, between Oglethorpe (An Electric Membership Corporation) and the United States of America.
4.2	Sixty-Ninth Supplemental Indenture, dated as of September 2, 2014, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2014 (FFB AB-8) Note and Series 2014 (RUS AB-8) Reimbursement Note.
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Michael L. Smith (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Michael L. Smith (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).
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: November 7, 2014 By: /s/ Michael L. Smith

Michael L. Smith
President and Chief Executive Officer

Date: November 7, 2014 /s/ Elizabeth B. Higgins

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