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

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**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 March 31, 2012

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File No. 000-53908



**OglethorpePowerCorporation**

**(An Electric Membership Corporation)**

(Exact name of registrant as specified in its charter)

**Georgia**

(State or other jurisdiction of  
incorporation or organization)

**58-1211925**

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

**2100 East Exchange Place**

**Tucker, Georgia**

(Address of principal executive offices)

**30084-5336**

(Zip Code)

Registrant's telephone number, including area code

**(770) 270-7600**

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

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

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

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

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

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**FOR THE QUARTER ENDED MARCH 31, 2012**

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## PART I—FINANCIAL INFORMATION

### Item 1. Financial Statements

#### *Oglethorpe Power Corporation*

#### *Condensed Balance Sheets*

*March 31, 2012 and December 31, 2011*

	(dollars in thousands)	
	2012	2011
	(Unaudited)	
<b>Assets</b>		
<b>Electric plant:</b>		
In service . . . . .	\$ 7,377,355	\$ 7,335,866
Less: Accumulated provision for depreciation . . . . .	(3,364,573)	(3,328,585)
	4,012,782	4,007,281
Nuclear fuel, at amortized cost . . . . .	300,736	284,205
Construction work in progress . . . . .	1,890,264	1,784,264
	6,203,782	6,075,750
<b>Investments and funds:</b>		
Nuclear decommissioning trust fund . . . . .	287,930	268,597
Deposit on Rocky Mountain transactions . . . . .	134,274	132,048
Investment in associated companies . . . . .	57,407	57,626
Long-term investments . . . . .	76,083	80,055
Restricted cash . . . . .	51,741	43,070
Other, at cost . . . . .	1,040	3,564
	608,475	584,960
<b>Current assets:</b>		
Cash and cash equivalents . . . . .	402,368	443,671
Restricted cash . . . . .	613	613
Restricted short-term investments . . . . .	110,526	106,676
Receivables . . . . .	139,359	124,650
Inventories, at average cost . . . . .	246,284	246,795
Prepayments and other current assets . . . . .	14,037	15,562
	913,187	937,967
<b>Deferred charges:</b>		
Deferred debt expense, being amortized . . . . .	66,368	67,470
Regulatory assets . . . . .	338,386	351,547
Other . . . . .	34,609	61,135
	439,363	480,152
	\$ 8,164,807	\$ 8,078,829

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

**Oglethorpe Power Corporation**  
**Condensed Balance Sheets**  
**March 31, 2012 and December 31, 2011**

	(dollars in thousands)	
	2012	2011
	(Unaudited)	
<b>Equity and Liabilities</b>		
<b>Capitalization:</b>		
Patronage capital and membership fees . . . . .	\$ 647,209	\$ 633,689
Accumulated other comprehensive margin . . . . .	1,327	618
	<u>648,536</u>	<u>634,307</u>
Long-term debt . . . . .	5,604,783	5,562,925
Obligation under capital leases . . . . .	144,243	146,781
Obligation under Rocky Mountain transactions . . . . .	134,274	132,048
	<u>6,531,836</u>	<u>6,476,061</u>
<b>Current liabilities:</b>		
Long-term debt and capital leases due within one year . . . . .	159,737	172,818
Short-term borrowings . . . . .	585,014	461,093
Accounts payable . . . . .	80,159	134,095
Accrued interest . . . . .	69,262	91,106
Accrued taxes . . . . .	8,414	21,118
Member power bill prepayments, current . . . . .	66,214	66,819
Other current liabilities . . . . .	27,707	25,080
	<u>996,507</u>	<u>972,129</u>
<b>Deferred credits and other liabilities:</b>		
Gain on sale of plant, being amortized . . . . .	25,494	26,113
Asset retirement obligations . . . . .	303,615	298,758
Member power bill prepayments, non-current . . . . .	41,675	35,500
Power sale agreement, being amortized . . . . .	51,201	54,816
Regulatory liabilities . . . . .	161,478	164,000
Other . . . . .	53,001	51,452
	<u>636,464</u>	<u>630,639</u>
	<u><u>\$8,164,807</u></u>	<u><u>\$8,078,829</u></u>

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

**Oglethorpe Power Corporation**  
**Condensed Statements of Revenues and Expenses (Unaudited)**  
**For the Three Months Ended March 31, 2012 and 2011**

	(dollars in thousands)	
	Three Months	
	2012	2011
<b>Operating revenues:</b>		
Sales to Members . . . . .	\$295,230	\$269,448
Sales to non-Members . . . . .	23,994	326
<b>Total operating revenues . . . . .</b>	<b>319,224</b>	<b>269,774</b>
<b>Operating expenses:</b>		
Fuel . . . . .	106,820	72,449
Production . . . . .	98,499	89,189
Depreciation and amortization . . . . .	44,544	34,405
Purchased power . . . . .	14,523	11,555
Accretion . . . . .	4,857	4,560
Deferral of Hawk Road and Murray Energy Facilities effect on net margin . . .	(12,075)	(8,319)
<b>Total operating expenses . . . . .</b>	<b>257,168</b>	<b>203,839</b>
<b>Operating margin . . . . .</b>	<b>62,056</b>	<b>65,935</b>
<b>Other income:</b>		
Investment income . . . . .	8,255	7,394
Other . . . . .	3,743	3,366
<b>Total other income . . . . .</b>	<b>11,998</b>	<b>10,760</b>
<b>Interest charges:</b>		
Interest expense . . . . .	76,007	70,666
Allowance for debt funds used during construction . . . . .	(20,419)	(15,228)
Amortization of debt discount and expense . . . . .	4,946	5,147
<b>Net interest charges . . . . .</b>	<b>60,534</b>	<b>60,585</b>
<b>Net margin . . . . .</b>	<b>\$ 13,520</b>	<b>\$ 16,110</b>

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

***Oglethorpe Power Corporation***  
***Condensed Statements of Comprehensive Margin (Unaudited)***  
***For the Three Months Ended March 31, 2012 and 2011***

	(dollars in thousands)	
	Three Months	
	<u>2012</u>	<u>2011</u>
<b>Net margin</b> . . . . .	<b><u>\$13,520</u></b>	<b><u>\$16,110</u></b>
Other comprehensive margin:		
Unrealized gain (loss) on available-for-sale securities . . . . .	<b><u>709</u></b>	<b><u>(21)</u></b>
<b>Total comprehensive margin</b> . . . . .	<b><u>\$14,229</u></b>	<b><u>\$16,089</u></b>

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 Three Months Ended March 31, 2012 and 2011*

	(dollars in thousands)		
	<b>Patronage Capital and Membership Fees</b>	<b>Accumulated Other Comprehensive Margin (Deficit)</b>	<b>Total</b>
Balance at December 31, 2010 . . . . .	\$595,952	\$ (469)	\$595,483
Components of comprehensive margin:			
Net margin . . . . .	16,110	—	16,110
Unrealized gain on available-for-sale securities . . . . .	—	(21)	(21)
Balance at March 31, 2011 . . . . .	\$612,062	\$ (490)	\$611,572
Balance at December 31, 2011 . . . . .	\$633,689	\$ 618	\$634,307
Components of comprehensive margin:			
Net margin . . . . .	13,520		13,520
Unrealized gain on available-for-sale securities . . . . .		709	709
<b>Balance at March 31, 2012 . . . . .</b>	<b>\$647,209</b>	<b>\$1,327</b>	<b>\$648,536</b>

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



**Oglethorpe Power Corporation**  
**Condensed Statements of Cash Flows (Unaudited)**  
**For the Three Months Ended March 31, 2012 and 2011**

	(dollars in thousands)	
	2012	2011
<b>Cash flows from operating activities:</b>		
Net margin	\$ 13,520	\$ 16,110
<b>Adjustments to reconcile net margin to net cash provided by operating activities:</b>		
Depreciation and amortization, including nuclear fuel	77,580	63,304
Accretion cost	4,857	4,560
Amortization of deferred gains	(1,415)	(1,415)
Allowance for equity funds used during construction	(851)	(547)
Deferred outage costs	(12,604)	(23,569)
Deferral of Hawk Road and Murray Energy facilities effect on net margin	(12,075)	(8,319)
Gain on sale of investments	(2,362)	(5,053)
Regulatory deferral of costs associated with nuclear decommissioning	(622)	2,348
Other	(1,923)	(1,848)
<b>Change in operating assets and liabilities:</b>		
Receivables	(12,349)	8,653
Inventories	511	(15,570)
Prepayments and other current assets	1,525	1,038
Accounts payable	(25,594)	(7,541)
Accrued interest	(21,844)	(30,225)
Accrued taxes	(12,704)	(16,838)
Other current liabilities	1,227	6,017
Member power bill prepayments	5,570	(14,174)
<b>Total adjustments</b>	<b>(13,073)</b>	<b>(39,179)</b>
<b>Net cash provided by (used in) operating activities</b>	<b>447</b>	<b>(23,069)</b>
<b>Cash flows from investing activities:</b>		
Property additions	(210,050)	(208,479)
Activity in decommissioning fund—Purchases	(288,010)	(284,469)
—Proceeds	287,040	283,188
Increase in restricted cash and cash equivalents	(8,671)	(168,701)
(Increase) decrease in restricted short-term investments	(3,850)	82,162
Decrease (increase) in investment in associated organizations	202	(256)
Activity in other long-term investments—Purchases	(486)	(402)
—Proceeds	8,600	300
Activity on interest rate options—Purchases	—	—
—Collateral received	8,670	—
Other	12,623	(1,185)
<b>Net cash used in investing activities</b>	<b>(193,932)</b>	<b>(297,842)</b>
<b>Cash flows from financing activities:</b>		
Long-term debt proceeds	69,139	257,351
Long-term debt payments	(42,907)	(54,931)
Increase (decrease) in short-term borrowings, net	123,921	(12,719)
Other	2,029	(138)
<b>Net cash provided by financing activities</b>	<b>152,182</b>	<b>189,563</b>
<b>Net decrease in cash and cash equivalents</b>	<b>(41,303)</b>	<b>(131,348)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>443,671</b>	<b>672,212</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 402,368</b>	<b>\$ 540,864</b>
<b>Supplemental cash flow information:</b>		
Cash paid for—		
Interest (net of amounts capitalized)	\$ 74,287	\$ 82,661
<b>Supplemental disclosure of non-cash investing and financing activities:</b>		
Change in plant expenditures included in accounts payable	\$ (27,699)	\$ 29,663

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

**Oglethorpe Power Corporation**  
**Notes to Unaudited Condensed Financial Statements**  
**For the Three Months ended March 31, 2012 and 2011**

- (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-month periods ended March 31, 2012 and 2011. 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, 2011, as filed with the SEC. The results of operations for the three-month period ended March 31, 2012 are not necessarily indicative of results to be expected for the full year. As noted in our 2011 Form 10-K, our revenues consist primarily of sales to our 39 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 2011 Form 10-K.)
- (B) *Fair Value Measurement.* 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 as of March 31, 2012 and December 31, 2011.

		Fair Value Measurements at Reporting Date Using		
		Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
	March 31, 2012	(Level 1)	(Level 2)	(Level 3)
		(dollars in thousands)		
Decommissioning funds:				
Domestic equity . . . . .	\$115,981	\$115,981	\$ —	\$ —
International equity . . . . .	44,784	44,784	—	—
Corporate bonds . . . . .	57,262	—	57,262	—
US Treasury and government agency securities . . . . .	50,627	50,627	—	—
Agency mortgage and asset backed securities . . . . .	10,916	—	10,916	—
Other . . . . .	8,360	8,360	—	—
Bond, reserve and construction funds . . . .	197	197	—	—
Long-term investments . . . . .	76,083	76,083	—	—
Interest rate options . . . . .	66,860	—	—	66,860 <sup>(1)</sup>
Natural gas swaps . . . . .	(9,580)	—	(9,580)	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2011	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
		(Level 1)	(Level 2)	(Level 3)
		(dollars in thousands)		
Decommissioning funds:				
Domestic equity . . . . .	\$102,285	\$102,285	\$ —	\$ —
International equity . . . . .	39,618	39,618	—	—
Corporate bonds . . . . .	41,338	—	41,338	—
US Treasury and government agency securities . . . . .	41,697	41,697	—	—
Agency mortgage and asset backed securities . . . . .	28,519	—	28,519	—
Derivative instruments . . . . .	(982)	—	—	(982)
Other . . . . .	16,122	16,122	—	—
Bond, reserve and construction funds . .	2,720	2,720	—	—
Long-term investments . . . . .	80,055	72,342	—	7,713 <sup>(2)</sup>
Interest rate options . . . . .	69,446	—	—	69,446 <sup>(1)</sup>
Natural gas swaps . . . . .	(7,220)	—	(7,220)	—

<sup>(1)</sup> Interest rate options as reflected on the condensed Balance Sheets include the fair value of the interest rate options offset by \$51,740,000 and \$43,070,000 of collateral received by the counterparties at March 31, 2012 and December 31, 2011, respectively.

<sup>(2)</sup> Represents auction rate securities investments we held.

The following tables present the changes in our Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2012 and 2011.

	Three Months Ended March 31, 2012		
	Decommissioning funds	Long-term investments	Interest rate options
	(dollars in thousands)		
Assets (Liabilities):			
Balance at January 1, 2012 . . . . .	\$(982)	\$ 7,713	\$69,446
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets) . . . . .	982	—	(2,586)
Impairment included in other comprehensive deficit . . . . .	—	887	—
Liquidations . . . . .	—	(8,600)	—
<b>Balance at March 31, 2012 . . . . .</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$66,860</b>

	Three Months Ended March 31, 2011	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at January 1, 2011 . . . . .	\$(452)	\$8,671
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets) . . . . .	(96)	—
Impairment included in other comprehensive deficit . . . . .	—	37
Liquidations . . . . .	—	(300)
Balance at March 31, 2011 . . . . .	\$(548)	\$8,408

On February 15, 2012, we sold our remaining \$8,600,000 of auction rate securities, which resulted in a loss of \$1,075,000. The loss was recorded as a regulatory asset and is being charged to income over a period of four years.

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

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 natural gas counterparties, and 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 March 31, 2012, all of the counterparties with transaction amounts outstanding under our hedging programs are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

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

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

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

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

At March 31, 2012 and December 31, 2011 the estimated fair value of our natural gas contracts was an unrealized loss of approximately \$9,580,000 and \$7,220,000, respectively.

As of March 31, 2012, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2012 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit totaling up to \$9,580,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of March 31, 2012 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2012 . . . . .	5.08
2013 . . . . .	1.37
2014 . . . . .	0.67
<b>Total</b> . . . . .	<b>7.12</b>

*Interest rate options.* We are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4. We have entered into a conditional term sheet with the Department of Energy to finance up to \$3.057 billion of the cost

to construct Vogtle Units No. 3 and No. 4. The term sheet provides for quarterly draws from 2012 through 2017 and interest rates that will be based on U.S. Treasury rates at the time of each draw, plus a fixed spread. In fourth quarter of 2011, we purchased interest rate options at a cost of \$100,000,000 to hedge the interest rates on approximately \$2.2 billion of the Department of Energy-guaranteed loan, representing a substantial portion of the expected borrowings from 2013 through 2017.

The interest rate options, commonly known as LIBOR swaptions, give us the right, but not the obligation, to enter into a swap in which we would pay a fixed rate and receive a floating LIBOR rate. However, the swaptions are required to be cash settled based on their value on the expiration date, thereby effectively capping our interest rates by offsetting the present value cost of an increase in interest rates above the fixed rate. The cash settlement value depends on the extent to which prevailing LIBOR swap rates exceed the fixed rate on the underlying swap, and the value would be zero if swap rates are at or below the fixed rate upon expiration. The fixed rates on the LIBOR swaptions we purchased are in the range of 100 to 200 basis points above current LIBOR swap rates and the weighted average fixed rate is 4.17%. The swaptions' expiration dates, which range from 2013 through 2017, are timed to match the expected quarterly draw dates of the Department of Energy-guaranteed loan advances to be hedged. As the interest rate options' value is independent from the Department of Energy-guaranteed loan, the interest rate options could also serve as a hedge of interest rates on an alternative source of financing.

We paid the entire premiums at the time we entered into these interest rate option transactions and have no additional payment obligations. However, upon expiration of the interest rate options, each counterparty will be obligated to pay us the cash value of the interest rate options, if any. These derivatives are recorded at fair value and hedge accounting is not applied. At March 31, 2012 and December 31, 2011, the fair value of these interest rate options was approximately \$66,860,000 and \$69,446,000, respectively. To manage our credit exposure to these 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 interest rate options outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from \$0 to \$10,000,000 depending on each counterparty's credit rating. As of March 31, 2012 and December 31, 2011, we held \$51,740,000 and \$43,070,000 of funds posted as collateral by the counterparties, respectively. The collateral received is recorded as long-term restricted cash on our balance sheets. The liability associated with the collateral is recorded as an offset to the fair values of the interest rate options, which are recorded within other deferred charges on the condensed balance sheets, results in a net carrying amount of the interest rate options of \$15,120,000 and \$26,376,000 at March 31, 2012 and December 31, 2011, respectively.

We are deferring gains or losses from the change in fair value of each interest rate option and related carrying and other incidental costs in accordance with our rate-making treatment. The deferred costs and deferred gains, if any, from the settlement of the interest rate options will be amortized and collected in rates over the life of the expected Department of Energy-guaranteed loan or alternative financing.

We estimate the value of the LIBOR swaptions utilizing an option pricing model based on several inputs including the notional amount, the forward LIBOR swap rates, the option volatility, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, as well as credit attributes, including the credit spread of the counterparty and the amount of credit support that is available for each swaption. The fair value of the swaptions is sensitive to certain of these inputs, especially option volatility. We are able to effectively observe all of these factors using a variety of market sources except for the credit spreads of certain counterparties and the option volatility. We are able to estimate option volatility implied by valuations we obtain from various sources, but the valuations, and therefore the implied option



volatilities vary considerably from one source to another. Since valuations of comparable instruments are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We considered both any intrinsic value and the remaining time value associated with the derivatives and considered counterparty credit risk in our determination of all estimated fair values. We believe the estimated fair values for the LIBOR swaptions we hold are based on the most accurate information available for these types of derivative contracts.

The following table reflects the notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of March 31, 2012:

Year	LIBOR Swaption Notional Dollar Amount (in thousands)
2013 . . . . .	\$ 754,452
2014 . . . . .	563,425
2015 . . . . .	470,625
2016 . . . . .	310,533
2017 . . . . .	80,169
<b>Total . . . . .</b>	<b>\$2,179,204</b>

The table below reflects the fair value of derivative instruments and their effect on our unaudited condensed balance sheet as of March 31, 2012.

	Balance Sheet Location	Fair Value (dollars in thousands)
<b>Designated as hedges under authoritative guidance related to derivatives and hedging activities:</b>		
<b>Liabilities</b>		
Natural Gas Swaps . . . . .	Other current liabilities	<u><u>\$ 9,580</u></u>
<b>Not designated as hedges under authoritative guidance related to derivatives and hedging activities:</b>		
<b>Assets</b>		
Interest rate options . . . . .	Other deferred charges	<u><u>\$66,860</u></u>



The following table presents the gains and (losses) on derivative instruments recognized in margin or deferred on the balance sheet for the three months ended March 31, 2012.

<b>Effect of Derivative Instruments on the Condensed Statement of Revenues and Expenses or Balance Sheet</b>		
	<b>Statement of Revenues and Expenses or Balance Sheet Location</b>	<b>Three months ended</b>
		(dollars in thousands)
<b>Designated as hedges under authoritative guidance related to derivatives and hedging activities</b>		
Natural Gas Swaps . . . . .	Purchased power	\$ (2,407)
Natural Gas Swaps . . . . .	Receivables	(9,580)
<b>Not designated as hedges under authoritative guidance related to derivatives and hedging activities</b>		
Nuclear decommissioning trust . . . . .	Regulatory asset	\$ 1,226
Nuclear decommissioning trust . . . . .	Regulatory asset	(1,643)
Interest rate options . . . . .	Regulatory asset	(33,140)
<b>Total losses on derivatives . . . . .</b>		<b><u>\$(45,544)</u></b>

(D) *Investments in Debt and Equity Securities.* Under the accounting guidance for Investments—Debt and Equity Securities, investment securities we hold are classified as available-for-sale. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from other comprehensive margin, except that, in accordance with our rate-making treatment, unrealized gains and losses from investment securities held in the nuclear decommissioning trust fund are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 95% of these gross unrealized losses were in effect for less than one year.

For those securities considered to be available-for-sale, the following table summarizes the activities for those securities as of March 31, 2012 and December 31, 2011:

		(dollars in thousands)		
		Gross Unrealized		
March 31, 2012	Cost	Gains	Losses	Fair Value
Equity . . . . .	\$148,898	\$43,951	\$(3,804)	\$189,045
Debt . . . . .	165,476	9,843	(3,588)	171,731
Other . . . . .	3,447	—	(13)	3,434
Total . . . . .	\$317,821	\$53,794	\$(7,405)	\$364,210
		Gross Unrealized		
December 31, 2011	Cost	Gains	Losses	Fair Value
Equity . . . . .	\$149,263	\$29,789	\$ (9,996)	\$169,056
Debt . . . . .	160,218	18,021	(11,063)	167,176
Other . . . . .	15,646	1,035	(1,541)	15,140
Total . . . . .	\$325,127	\$48,845	\$(22,600)	\$351,372

(E) *Recently Issued or Adopted Accounting Pronouncements.* In May 2011, the FASB issued Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards. These changes were effective for us on January 1, 2012. Our adoption of this standard did not have a material effect on our financial statements.

In June 2011, the FASB issued Accounting Standards Update 2011-05 “Comprehensive Income Presentation of Financial Statements” which amended certain provisions of ASC 220 “Comprehensive Income”. These provisions change the presentation requirements for other comprehensive income and total comprehensive income and require one continuous statement or two separate but consecutive statements. Presentation of other comprehensive income in the statement of stockholders’ equity is no longer permitted. These provisions are effective for fiscal and interim periods beginning after December 15, 2011. The adoption of these provisions did not have a material effect on our consolidated financial statements. a material effect on our financial statements.

In December 2011, the FASB issued “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities,” which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. This guidance is effective for our fiscal year ending December 31, 2013. We do not expect the adoption of this standard to have a material impact on our financial statements.

(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 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 2011 Form 10-K.

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 December 31, 2010 .....	\$ (469)
Unrealized loss .....	(21)
Balance at March 31, 2011 .....	\$ (490)
Balance at December 31, 2011 .....	\$ 618
Unrealized gain .....	709
<b>Balance at March 31, 2012 .....</b>	<b><u>\$1,327</u></b>

(G) *Environmental Matters.* As is typical for electric utilities, we are subject to various federal, state and local air and water quality requirements which, among other things, regulate emissions of pollutants, such as particulate matter, sulfur dioxide, nitrogen oxides and mercury into the air and discharges of other pollutants, including heat, into waters of the United States, which represent significant future risks and uncertainties. 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. Finally, we are subject to federal, state and local waste disposal requirements that regulate the manner of transportation, storage and disposal of various types of waste.

In general, environmental requirements are becoming increasingly stringent. Any new requirements in the future but not in existence now may substantially increase the cost of electric service by requiring changes in the design or operation of existing facilities or changes or delays in the location, design, construction or operation of new facilities. Failure to comply with any new requirements could result in the imposition of civil and criminal penalties as well as the complete shutdown of individual generating units not in compliance. Certain of our debt instruments and credit agreements require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current or future environmental laws and regulations. We believe that we are in compliance with those environmental regulations currently applicable to our business and operations. Should we fail to be in compliance with these requirements, or any new requirements, it would constitute a default under such debt instruments and credit agreements. Although it is our intent to comply with applicable current and future regulations, we cannot provide assurance that we will always be in compliance with such requirements.

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.

We are currently not subject to any environmental or other loss contingencies for which we believe it is probable or reasonably possible that a loss has been incurred that would be material to our financial position, results of operations or cash flows.

- (H) *Restricted Cash.* At March 31, 2012 and December 31, 2011, we had restricted cash totaling \$52,354,000 and \$43,683,000, respectively, of which \$51,741,000 and \$43,070,000 was classified as long-term. The long-term restricted cash balance at March 31, 2012 and December 31, 2011 consisted of funds posted as collateral by counterparties to our interest rate options. The current portion of restricted cash at March 31, 2012 and December 31, 2011 primarily consisted of clean renewable energy bond proceeds on deposit with CoBank, ACB to fund a qualifying project at the Rocky Mountain Pumped Storage Hydroelectric Facility.
- (I) *Restricted Short-term Investments.* At March 31, 2012 and December 31, 2011, we had \$110,526,000 and \$106,676,000, respectively, on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted funds will be utilized for future Rural Utilities Service Federal Financing Bank debt service payments. The deposit earns interest at a Rural Utilities Service guaranteed rate of 5% per annum.
- (J) *Regulatory Assets and Liabilities.* We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery from our members in future revenues through rates under the wholesale power contracts with our members extending through December 31, 2050. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from our members.

The following regulatory assets and liabilities are reflected on the accompanying condensed balance sheets as of March 31, 2012 and December 31, 2011.

	2012	2011
	(dollars in thousands)	
<i>Regulatory Assets:</i>		
Premium and loss on reacquired debt . . . . .	\$ 95,483	\$ 98,538 <sup>(a)</sup>
Amortization on capital leases . . . . .	41,431	46,627 <sup>(b)</sup>
Outage costs . . . . .	45,656	42,866 <sup>(c)</sup>
Interest rate swap termination fees . . . . .	20,318	21,316 <sup>(d)</sup>
Asset retirement obligations . . . . .	10,357	29,341 <sup>(e)</sup>
Depreciation expense . . . . .	50,853	51,209 <sup>(f)</sup>
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs . . . . .	19,487	17,602 <sup>(g)</sup>
Interest rate options cost . . . . .	33,589	30,735 <sup>(h)</sup>
Deferral of effects on net margin—Murray Energy facility . . . . .	10,792	3,536 <sup>(k)</sup>
Other regulatory assets . . . . .	10,420	9,777 <sup>(i)</sup>
<i>Total Regulatory Assets</i> . . . . .	<b>\$338,386</b>	<b>\$351,547</b>
<i>Regulatory Liabilities:</i>		
Accumulated retirement costs for other obligations . . . . .	\$ 32,795	\$ 32,687 <sup>(e)</sup>
Net benefit of Rocky Mountain transactions . . . . .	46,984	47,783 <sup>(j)</sup>
Deferral of effects on net margin—Hawk Road Energy facility . . . . .	10,992	15,811 <sup>(k)</sup>
Major maintenance sinking fund . . . . .	29,115	28,524 <sup>(l)</sup>
Deferred debt service adder . . . . .	40,062	37,586 <sup>(m)</sup>
Other regulatory liabilities . . . . .	1,530	1,609 <sup>(i)</sup>
<i>Total Regulatory Liabilities</i> . . . . .	<b>\$161,478</b>	<b>\$164,000</b>
Net regulatory assets . . . . .	<b><u>\$176,908</u></b>	<b><u>\$187,547</u></b>

- (a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt amortized over the period of the refunding debt, which range up to 31 years.
- (b) Recovery over the remaining life of the leases through 2021.
- (c) Consists of both coal-fired and nuclear refueling outage costs. These outage costs are amortized on a straight-line basis to expense over an 18 to 24-month period.
- (d) Represents amount paid on settled interest rate swaps arrangements that are being amortized over the remaining life of the refunded variable rate bonds or 2016 and 2019, respectively.
- (e) Accounting and reporting performed in accordance with authoritative guidance related to asset retirement obligations. We record an offsetting regulatory asset or liability to reflect the 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) 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 which is expected to be 2016 and 2017, respectively, and amortized over the life of the units.
- (h) Deferral of net loss (gains) associated with the change in fair value of the interest rate options to hedge interest rates on a portion of expected borrowings related to Vogtle Units No. 3 and No. 4 construction. Amortization will commence effective with the expected principal repayment of the Department of Energy (DOE)-guaranteed loan in 2017 and amortized over the expected remaining life of DOE-guaranteed loan.
- (i) The amortization period for other regulatory assets range up to 37 years and the amortization period of other regulatory liabilities range up to 7 years.
- (j) Net benefit associated with Rocky Mountain lease transactions is amortized to income over the 30-year lease-back period.
- (k) Effects on net margin for Hawk Road and Murray will be deferred until the end of 2015 and amortized over the remaining life of each plant.
- (l) Represents collections for future major maintenance costs that will offset by deferred revenues when incurred.
- (m) Collections to fund debt payments in excess of depreciation expense through the end of 2025; deferred revenues will be amortized over the remaining useful life of the plants.

- (K) *Member Power Bill Prepayments.* We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. At March 31, 2012, member power bill prepayments as reflected on the unaudited condensed balance sheet, including unpaid discounts, were \$107,889,000, of which, \$66,214,000 is classified as a current liability and \$41,675,000 as deferred credits and other liabilities. The prepayments are being applied against members' power bills through November 2017, with the majority of the remaining balance scheduled to be applied by the end of 2013.
- (L) *Debt.* During March 2012, we received advances on Rural Utilities Service-guaranteed/Federal Financing Bank loans totaling \$69,139,000 for general and environmental improvements at existing plants.
- (M) *Sales to Non-Members.* For the three-month period ended March 31, 2012, we had \$23,994,000 of sales to non-members. These sales consisted primarily of capacity and energy sales to Georgia Power under an agreement to sell the entire output of Murray Unit No. 1 through May 31, 2012. These sales also included energy generated at Murray Unit No. 2 sold to non-members.

## **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 39 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.

### *Forward-Looking Statements and Associated Risks*

This Quarterly Report on Form 10-Q contains forward-looking statements, including statements regarding, among other items, (i) anticipated financing transactions by us, (ii) our future capital expenditure requirements and funding sources and (iii) achievement of a margins for interest ratio at the minimum requirement contained in our first mortgage indenture and, in the case that our board of directors approves a budget for a particular fiscal year that seeks to achieve a higher margins for interest ratio, such higher board-approved margins for interest ratio. These forward-looking statements are based largely on our current expectations and are subject to a number of risks and uncertainties, some of which are beyond our control. For a discussion of some factors that could cause actual results to differ materially from those anticipated by these forward-looking statements, see "Item 1A—RISK FACTORS" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011. In light of these risks and uncertainties, there can be no assurance that events anticipated by the forward-looking statements contained in this Quarterly Report on Form 10-Q will in fact transpire.

### **Results of Operations**

#### For the Three Months Ended March 31, 2012 and 2011

#### *Net Margin*

Throughout the year, we monitor our operating results and, with board approval, make budget adjustments when and as necessary to ensure our targeted margins for interest ratio is achieved. Under our first mortgage indenture, we are required to establish and collect rates that are reasonably expected, together with our other revenues, to yield at least a 1.10 margins for interest ratio in each fiscal year. However, to enhance margin coverage during this period of generation facility construction and acquisition, our board of directors approved budgets for 2011 and 2012 to achieve a 1.14 margins for interest ratio. As our construction and acquisition program evolves, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below the 1.10 margins for interest ratio required under our first mortgage indenture.

Our net margin for the three-month period ended March 31, 2012 was \$13.5 million compared to \$16.1 million for the same period of 2011. We expect a net margin of \$39.7 million for the year ending December 31, 2012 which will achieve, but not exceed, the targeted margins for interest ratio of 1.14.

#### *Operating Revenues*

Our operating revenues fluctuate from period to period based on several factors, including weather and other seasonal factors, load requirements in our members' service territories, operating costs, availability of electric generation resources, our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights, and 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 9.6% in the three-month period ended March 31, 2012 compared to the same period of 2011. Megawatt-hour sales to members increased 18.1% for the three-month period ended March 31, 2012 compared to the same period of 2011. The average total revenue per megawatt-hour from sales to members decreased 7.2% for the three-month period ended March 31, 2012 compared to the same period of 2011.

The components of member revenues for the three-month periods ended March 31, 2012 and 2011 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended March 31,	
	2012	2011
Capacity revenues . . . . .	\$ 174,187	\$ 171,261
Energy revenues . . . . .	121,043	98,187
Total . . . . .	\$ 295,230	\$ 269,448
Kilowatt-hours sold to members . . . . .	4,702,799	3,982,856
Cents per kilowatt-hour . . . . .	6.28¢	6.77¢

Energy revenues were 23.3% higher for the three-month period ended March 31, 2012 compared to the same period of 2011. Our average energy revenue per megawatt-hour from sales to members increased 4.4% for the three-month period ended March 31, 2012 as compared to the same period of 2011. The increase in energy revenues resulted primarily from higher megawatt-hour sales to our members primarily as a result of higher generation at the Chattahoochee Energy Facility in 2012. Chattahoochee had an unplanned outage in the first quarter of 2011 and was not placed back into service until April 2011. For a discussion of fuel costs and total generation, see “—Operating Expenses.”

*Sales to Non-Members.* Sales to non-members for the three-month period ended March 31, 2012 consisted primarily of capacity and energy sales to Georgia Power Company under an agreement to sell the entire output of Murray Unit No. 1 through May 31, 2012. In addition, we sold energy generated at Murray Unit No. 2 to non-members. We acquired Murray in April 2011.

#### *Operating Expenses*

Operating expenses for the three-month period ended March 31, 2012 increased 26.2% compared to the same period of 2011. The increase in operating expenses was primarily due to higher fuel, production, depreciation and amortization and purchased power costs.



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

Fuel Source	Three Months Ended March 31,			
	2012		2011	
	Cost	Generation	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal . . . . .	\$ 52,995	1,679,195	\$50,564	1,682,119
Nuclear . . . . .	20,331	2,433,717	16,143	2,396,999
Gas . . . . .	32,878	1,396,212	5,091	22,911
Pumped Storage . . . . .	616	(79,149)	651	(74,042)
	<u>\$106,820</u>	<u>5,429,975</u>	<u>\$72,449</u>	<u>4,027,987</u>
	Cost	Purchased	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power . . . . .	<u>\$ 14,523</u>	<u>45,104</u>	<u>\$11,555</u>	<u>21,027</u>

For the three-month period ended March 31, 2012, total fuel costs increased 47.4% and total megawatt-hour generation increased 34.8% compared to the same period of 2011. Average fuel costs per megawatt-hour increased 16.4% in the three-month period ended March 31, 2012 compared to the same period of 2011. The increase in total fuel costs and generation resulted primarily from increased natural gas-fired generation of 1,373,000 megawatt-hours due to generation from Murray which was sold to non-members and generation from Chattahoochee which was sold to our members. As discussed previously, Murray was acquired in April 2011 and Chattahoochee was unavailable during first quarter of 2011. The increase in natural gas-fired generation was the primary contributor to the increase in average fuel costs per megawatt-hour of generation; however, during the first quarter of 2012, natural gas prices continued to decline and nearly reached recent historical lows, which has made natural gas-fired generation resources a more economical and cost-effective source of energy generation than in prior years.

Total production costs increased 10.4% for the three-month period ended March 31, 2012 compared to the same period of 2011. The increase in production was primarily due to operation and maintenance expenses incurred at Murray, increased general operations and maintenance expenses at Plants Vogtle and Hatch and higher operations and maintenance expenses at Chattahoochee. These increases were offset somewhat by lower production costs for the Hawk Road Energy Facility in the first quarter of 2012 as production costs for Hawk Road in the first quarter of 2011 included expenses for planned outage work and for repair of a damaged transformer.

Depreciation and amortization costs increased 29.5% for the three-month period ended March 31, 2012 compared to the same period of 2011. This increase resulted primarily from depreciation of Murray.

Total purchased power costs increased 25.7% for the three-month period ended March 31, 2012 compared to the same period of 2011. The increase in purchased power costs was primarily due to higher realized losses incurred for natural gas financial contracts utilized for managing exposure to fluctuations in the market prices of natural gas.

The effect on net margin for Murray and Hawk Road is being deferred until 2016 at which time the amounts will be amortized over the remaining life of the plants. In implementing the deferral plans, we assumed that our members would generally not require energy from the plants until 2016. If any of our members subscribed to Murray elect to take energy from Murray prior to 2016, the deferral of the effect on net margin would terminate for that member and the amortization of that member's deferral

would commence immediately. The changes in cost deferrals in 2012 compared to 2011 resulted from the Murray and Hawk Road costs discussed above in production costs.

#### *Other Income*

Other income increased 11.5% for the three-month period ended March 31, 2012 compared to the same period of 2011 primarily due to increased investment income resulting from higher funds deposited in the Rural Utilities Service Cushion of Credit Account.

#### *Interest charges*

Interest expense increased by 7.6% in the three-month period ended March 31, 2012 compared to the same period of 2011. This increase is primarily due to the increased debt issued for the purpose of financing the construction of Vogtle Units No. 3 and No. 4.

Allowance for debt funds used during construction increased by 34.1% in the three-month period ended March 31, 2012 compared to the same period of 2011 primarily due to construction expenditures for Vogtle Units No. 3 and No. 4.

### **Financial Condition**

#### Balance Sheet Analysis as of March 31, 2012

##### *Assets*

Cash used for property additions for the three-month period ended March 31, 2012 totaled \$210.0 million. Of this amount, approximately \$102.0 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, \$34.3 million for purchases of nuclear fuel and \$27.3 million was related to environmental control systems being installed primarily at Plant Scherer. The remaining expenditures were primarily for normal additions and replacements to existing generation facilities.

Cash and cash equivalents decreased by \$41.3 million in the three-month period ended March 31, 2012. The decrease was primarily attributed to capital expenditures for property additions, that were offset by \$123.9 million in cash received from short-term borrowings and \$69.1 million in advances received from the Rural Utilities Service for environmental and general improvements.

The \$110.5 million of restricted short-term investments at March 31, 2012 represented funds deposited into a Rural Utilities Service Cushion of Credit Account with the U.S. Treasury that earns interest at a guaranteed rate of 5% per annum. The funds, including interest earned thereon, can only be applied to debt service on Rural Utilities Service and Rural Utilities Service-guaranteed Federal Financing Bank notes. Decisions regarding how to apply the funds are guided by the interest rate environment and our anticipated liquidity needs.

Receivables increased by \$14.7 million in the three-month period ended March 31, 2012. The December 31, 2011 receivables balance included approximately \$17.7 million of credits available to the members for a board approved reduction to 2011 revenue requirements as a result of margins collected in excess of our 2011 target. A portion of the increase in receivables was due to these credits being utilized by the members during the first quarter of 2012. Partially offsetting the increase was a decrease in the receivable balance for certain project costs written off in December 2011.

Other deferred charges decreased \$26.5 million in the three-month period ended March 31, 2012 due to an \$11.3 million decrease in the fair value of our interest rate options and a \$10.2 million decrease in Georgia Power related deferred equipment prepayments that were expensed or capitalized in connection with a planned outage at Hatch Unit No. 1 in the first quarter of 2012. Also contributing to the decrease was a \$5.1 million decrease in the amortized value of the intangible asset associated with

the purchase and sale agreement with Georgia Power that was acquired as part of the 2011 Murray acquisition.

#### *Equity and Liabilities*

Short-term borrowings for the three-month period ended March 31, 2012 increased \$123.9 million. The increase was primarily due to the issuance of commercial paper to fund capital expenditures related to Vogtle Units No. 3 and No. 4.

Accounts payable decreased \$53.9 million in the three-month period ended March 31, 2012 primarily due to a decrease in the payable to Georgia Power for operation and maintenance costs for our co-owned plants and capital costs primarily associated with Vogtle Units No. 3 and No. 4 construction.

The \$21.8 million increase in accrued interest for the three-month period ended March 31, 2012 was due to the normal timing differences between interest payments and interest expense accruals.

Accrued taxes decreased \$12.7 million for the three-month period ended March 31, 2012 as a result of payments made, when due, for 2011 property taxes, which exceeded normal property tax accruals.

Member power bill prepayments represent funds received from the members for prepayment of their monthly power bills. At March 31, 2012, \$66.2 million of member power bill prepayments was classified as a current liability and \$41.7 million of member power bill prepayments was classified as a long-term liability. During the three-month period ended March 31, 2012, approximately \$14.8 million of prepayments were received from the members and approximately \$9.3 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note K of Notes to Unaudited Condensed Financial Statements and “—Capital Requirements and Liquidity and Sources of Capital—*Liquidity*.”

#### Capital Requirements and Liquidity and Sources of Capital

##### *Future Power Resources*

To meet the energy needs of our members, we are in a period of generation expansion. In addition to acquiring more than 2,000 megawatts of capacity through the purchases of the Hawk Road, Hartwell and Murray energy facilities, members have subscribed to a 30% interest in Vogtle Units No. 3 and No. 4 (660 megawatts), which are currently under construction. For further discussion of our planned future generation resources and projected capital expenditures, see “Item 1—BUSINESS—Our Power Supply Resources—*Future Power Resources*” and “Item 7—MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*” in our 2011 Form 10-K.

*Vogtle Units No. 3 and No. 4.* We, along with Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton, the “Co-owners,” and Westinghouse Electric Company LLC and Stone & Webster, Inc., the “Consortium,” have established both informal and formal dispute resolution procedures in accordance with the Engineering, Procurement and Construction Contract to design, engineer, procure, construct, and test Vogtle Units No. 3 and No. 4 in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, and the Consortium have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

During the course of construction activities, issues have arisen that may impact the project budget and schedule, including costs associated with design changes to the Westinghouse AP1000 Design Certification 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. Georgia Power, on behalf of the Co-owners, and the Consortium have begun negotiations regarding these issues, including the assertion by the Consortium that the Co-owners are responsible for these costs under the terms of the contract. In preliminary discussions, the Consortium provided its initial estimate of its proposed adjustment to the contract price. Based on our ownership interest, the Consortium's estimated adjustment attributable to us is approximately \$250 million in 2008 dollars with respect to these issues, which includes an initial estimate of costs for efforts to maintain the projected in-service dates of 2016 and 2017 for Vogtle Units No. 3 and No. 4, respectively. Georgia Power, on behalf of the Co-owners, has not agreed with the amount of these proposed adjustments or that the Co-owners have responsibility for any costs related to these issues. Georgia Power expects negotiations with the Consortium to continue over the next several months during which time the parties will attempt to reach a mutually acceptable compromise of their positions. If a compromise cannot be reached, formal dispute resolution, including litigation, may follow. Georgia Power, on behalf of the Co-owners, intends to vigorously defend its positions. Additional claims by the Consortium or Georgia Power, on behalf of the Co-owners, are expected to arise throughout the construction of Vogtle Units No. 3 and No. 4.

In addition, there are processes in place to assure compliance with the design requirements specified in the DCD and the combined licenses, including rigorous inspection by Southern Nuclear Operating Company and the Nuclear Regulatory Commission that occurs throughout construction. A recent routine Nuclear Regulatory Commission inspection identified that certain details of the rebar construction in the Vogtle Unit No. 3 nuclear island were not consistent with the DCD. Georgia Power expects to receive official notice of these findings from the Nuclear Regulatory Commission. Georgia Power, on behalf of the Co-owners, is currently engaged in constructive discussions with the Consortium to identify appropriate corrective actions. Various inspection issues are expected as construction proceeds.

On February 16, 2012, a group of four plaintiffs who had intervened in the Nuclear Regulatory Commission's combined license proceedings for Vogtle Units No. 3 and No. 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the Commission's issuance of the combined licenses. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the Commission's certification of the DCD. On April 3, 2012, the Court granted a motion filed by these two groups to consolidate their challenges. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the order issuing the combined licenses for Vogtle Units No. 3 and No. 4 with the U.S. District Court for the District of Columbia. Georgia Power, on behalf of the Co-owners, has filed a motion to intervene in these proceedings and intends to vigorously contest these petitions.

There are other pending technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4. Similar additional challenges at both the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time. See "Item 1A—RISK FACTORS" in our 2011 Form 10-K for a discussion of certain risks associated with the licensing, construction and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

As of March 31, 2012, our total capitalized costs to date for Vogtle Units No. 3 and No. 4 were \$1.4 billion.

## Environmental Regulations

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

On April 13, 2012, EPA published a proposed rule to create new source performance standards (NSPS) for greenhouse gas emissions (specifically carbon dioxide) from certain new electric generating units under section 111(b) of the Clean Air Act. The proposed rule would apply to certain large, new fossil fuel-fired electric utility units, including boilers, integrated gasification combined cycle units and stationary combined cycle units. New units—those that commence construction after April 13, 2012—are covered, although a special exemption is provided to transitional sources, defined as those that have received certain air quality permit approvals and commence construction by April 13, 2013. The rule does not apply to existing units that undergo modifications or to reconstructed sources. Hence, it is not expected to impact our existing coal-fired plants or combined cycle facilities. However, once EPA promulgates a NSPS for a category of new sources, it is required to establish guidelines requiring states to develop emission standards for the same category of existing sources. Thus, greenhouse gas NSPS for existing sources may be issued at some point in the future.

We cannot predict at this time the ultimate effects this proposed regulation may have on the operations and costs of our existing or future power plants, including capital costs. For further discussion regarding potential effects on our business from environmental regulations, including potential capital requirements, see “Item 1—BUSINESS—ENVIRONMENTAL AND OTHER REGULATION,” “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 2011 Form 10-K.

## Liquidity

At March 31, 2012, we had \$1.5 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included \$402 million in cash and cash equivalents and \$1.1 billion of unused and available committed credit arrangements.

On March 31, 2012, we had in excess of \$1.9 billion of committed credit arrangements in place comprised of the five separate facilities reflected in the table below.

Committed Credit Facilities			
	Authorized Amount	Available 3/31/2012	Expiration Date
	(dollars in millions)		
<i>Unsecured Facilities:</i>			
Syndicated Line of Credit <sup>(1)</sup>	\$1,265	\$ 544 <sup>(2)</sup>	June 2015
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	33 <sup>(3)</sup>	December 2013
<i>Secured facilities:</i>			
CoBank Line of Credit	150	150	November 2012
CFC Line of Credit <sup>(4)</sup>	250	250	December 2013
<b>Total</b>	<b>\$1,925</b>	<b>\$1,087</b>	

<sup>(1)</sup> This credit facility is syndicated among fourteen banks led by Bank of America as administrative agent.

<sup>(2)</sup> Of the portion of this facility that is unavailable, \$585 million is dedicated to support commercial paper we have issued and \$136 million relates to letters of credit issued under this facility to support variable rate demand bonds.

<sup>(3)</sup> Of the portion of this facility that is unavailable, \$114 million relates to letters of credit issued under this facility to support variable rate demand bonds and \$3 million relates to letters of credit issued to post collateral to third parties.

<sup>(4)</sup> This facility has a term loan option that can extend the maturity out to December 31, 2043.

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

Due to the significant expenditures related to environmental compliance projects and new generation facilities, we have been funding our capital requirements through a combination of funds generated from operations and interim and long-term borrowings. In particular, we are using commercial paper, backed by the syndicated line of credit, to provide interim financing for construction of Vogtle Units No. 3 and No. 4, for a portion of the cost to acquire Murray and for the upfront payments made in connection with our interest rate hedging program until long-term financing is put in place.

We have the flexibility to use the syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up outstanding commercial paper. We can issue commercial paper in amounts that do not exceed the amount of any committed backup line of credit, thereby providing 100% dedicated support for any commercial paper outstanding.

Like the lines of credit from National Rural Utilities Cooperative Finance Corporation (CFC), JPMorgan Chase Bank and CoBank, ACB, funds may be advanced under the syndicated line of credit for general working capital purposes. In addition, under some of our committed credit facilities we have the ability to issue letters of credit totaling \$910 million in the aggregate, of which \$658 million remained available at March 31, 2012. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, any amounts drawn under the syndicated line for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue.

Several of our line of credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At March 31, 2012, the required minimum level was \$575 million and our actual patronage capital was \$647 million. Additional covenants contained in several of our credit facilities limit the amount of secured indebtedness and unsecured indebtedness we can have outstanding. At March 31, 2012, the most restrictive of these covenants limits our secured indebtedness to \$9.5 billion and our unsecured indebtedness to \$4.0 billion. At March 31, 2012, we had \$5.5 billion of secured indebtedness and \$845 million of unsecured indebtedness outstanding, which was well within the covenant thresholds.

We also have a power bill prepayment program that provides us with an additional source of liquidity. Under the program, members can prepay their power bills from us at a discount for an agreed upon number of months in advance, after which the prepayments are credited against the participating members' monthly power bills. The discount is comparable to our avoided cost of borrowing. As of March 31, 2012, the balance of member prepayments received but not yet credited to their power bills was \$107.9 million. We expect to apply the prepayments against the participating members' power bills through November 2017, with the majority of the remaining balance scheduled to be applied by the end of 2013. For more information regarding the power bill prepayment program, see Note K of Notes to Unaudited Condensed Financial Statements.

At March 31, 2012, current assets included \$110.5 million of restricted short-term investments pursuant to deposits made to a Rural Utilities Service Cushion of Credit Account. Our decisions regarding how to apply the funds are guided by the interest rate environment and our anticipated liquidity needs. On April 2, 2012, the account balance was reduced to \$61.9 million as we utilized \$48.6 million to pay our quarterly debt service payment due on that date.



## *Financing Activities*

*First Mortgage Indenture.* At March 31, 2012, we had \$5.5 billion of long-term debt outstanding under our first mortgage indenture secured equally and ratably by a lien on substantially all of our tangible and some of our intangible assets, including those we acquire in the future. See “Item 7—MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities—First Mortgage Indenture*” in our 2011 Form 10-K for a further discussion of our first mortgage indenture.

*Bond Financing.* On April 2, 2012, we closed a \$32.4 million financing transaction that included two components. In one component the Development Authority of Monroe County issued, on our behalf, \$10.1 million of term rate pollution control revenue bonds for the purpose of refinancing a like amount of pollution control revenue bonds previously issued by the authority on our behalf that had matured. This tax-exempt debt is secured under our first mortgage indenture. The second component entails a remarketing of \$22.3 million of pollution control bonds issued previously on our behalf by the Development Authority of Burke County due to a mandatory tender of these bonds which were originally issued in a term rate period that ended March 31, 2012. Both components now bear interest in a term rate period that ends on February 28, 2013.

In a separate transaction on April 2, 2012, Georgia Transmission Corporation refinanced \$40.2 million of pollution control bonds for which we were secondarily obligated. Upon this refinancing, we are no longer obligated for these bonds or any other of Georgia Transmission’s debt obligations. For further discussion regarding our prior obligations related to Georgia Transmission, see “Item 7—MANAGEMENT’S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION—Financial Condition—*Off-Balance Sheet Arrangements—Georgia Transmission Debt Assumption*” and Note 10 to “Item 8—FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA—Notes to Consolidated Financial Statements” in our 2011 Form 10-K.

*Rural Utilities Service-Guaranteed Loans.* We have six approved Rural Utilities Service-guaranteed loans, being funded through the Federal Financing Bank, totaling \$1.7 billion that are in various stages of being drawn down, with \$1.0 billion remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture.

*Department of Energy-Guaranteed Loan.* The Department of Energy loan guarantee program was authorized pursuant to Title XVII of the Energy Policy Act of 2005, which is intended to support innovative technologies to reduce air pollutants, including greenhouse gases. Pursuant to this program, in May 2010 we signed a conditional term sheet with the Department of Energy that sets forth the general terms of a loan and related loan guarantee that would fund 70% of the estimated \$4.2 billion cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4, not to exceed \$3.057 billion. The loan structure would entail a loan that is funded by the Federal Financing Bank carrying a federal loan guarantee provided by the Department of Energy, with the debt secured under our first mortgage indenture.

Final approval and issuance of a loan guarantee by the Department of Energy is subject to negotiation of definitive agreements, completion of due diligence by the Department of Energy and satisfaction of other conditions. Therefore, there can be no assurance that the Department of Energy will ultimately issue the loan guarantee to us. We anticipate that any project costs not funded under the Department of Energy loan guarantee program would be financed through the issuance of taxable bonds.

Of the approximately \$1.2 billion of currently estimated project costs not expected to be funded under the Department of Energy loan guarantee program, we have already financed \$1.15 billion through the issuance of first mortgage bonds.

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*” and for a discussion of our activities to mitigate the risk of rising interest rates associated with this financing, see “Item 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK—Interest Rate Risk” in our 2011 Form 10-K.

**Newly Adopted or Issued Accounting Standards**

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

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

Not Applicable.

**Item 4. Controls and Procedures**

As of March 31, 2012, 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.



## **PART II—OTHER INFORMATION**

### **Item 1. Legal Proceedings**

We are a party to various actions and proceedings incidental to our normal business. Liability in the event of final adverse determination in any of these matters is either covered by insurance or, in the opinion of our management, after consultation with counsel, should not in the aggregate have a material adverse effect on our financial position, results of operations or cash flows.

### **Item 1A. Risk Factors**

There have not been any material changes in our risk factors from those reported in “Item 1A—RISK FACTORS” of our 2011 Form 10-K.

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

Not Applicable.

### **Item 3. Defaults upon Senior Securities**

Not Applicable.

### **Item 4. Mine Safety Disclosures**

Not Applicable.

### **Item 5. Other Information**

Not Applicable.

**Item 6. Exhibits**

<u>Number</u>	<u>Description</u>
4.1	Sixty-Second Supplemental Indenture, dated as of April 1, 2012, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to the Series 2012 A (Monroe) Note.
10.1 <sup>(1)</sup>	Amendment No. 4, dated as of May 2, 2011, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended June 30, 2011, filed with the SEC on August 5, 2011.)
10.2 <sup>(1)</sup>	Amendment No. 5, dated as of February 7, 2012, to the Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for Oglethorpe, Municipal Electric Authority of Georgia, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse and Stone & Webster, as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Incorporated by reference to Exhibit 10(c)(2) of Georgia Power Company's Form 10-Q for the quarterly period ended March 31, 2012, filed with the SEC on May 7, 2012.)
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Thomas A. 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 Thomas A. 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).
99.1	Member Financial and Statistical Information (for calendar years 2009-2011).
101	XBRL Interactive Data File.

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<sup>(1)</sup> Confidential treatment has been requested for certain confidential portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934. In accordance with Rule 24b-2, these confidential portions have been omitted from this exhibit and filed separately with the SEC.

## 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: May 11, 2012

By: /s/ Thomas A. Smith

\_\_\_\_\_  
Thomas A. Smith  
President and Chief Executive Officer  
(Principal Executive Officer)

Date: May 11, 2012

/s/ Elizabeth B. Higgins

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