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**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 number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE  
(Exact name of registrant as specified in its charter)

VIRGINIA  
(State or other jurisdiction of  
incorporation or organization)

23-7048405  
(I.R.S. employer  
identification no.)

4201 Dominion Boulevard, Glen Allen, Virginia  
(Address of principal executive offices)

23060  
(Zip code)

\_\_\_\_\_  
(804) 747-0592

(Registrant's telephone number, including area code)

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 (§232.405 of this chapter) 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 "larger accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Larger accelerated filer \_\_\_ Accelerated filer \_\_\_  
Non-accelerated filer  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

The Registrant is a membership corporation and has no authorized or outstanding equity securities.

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## GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-Q are defined below:

<u>Abbreviation or Acronym</u>	<u>Definition</u>
ACES	Alliance for Cooperative Energy Services Power Marketing, LLC
Alstom	Alstom Power, Inc.
Bear Island	Bear Island Paper WB LLC
CAIR	Clean Air Interstate Rule
Clover	Clover Power Station
CO <sub>2</sub>	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
Indenture	Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated January 1, 2011, of ODEC with Branch Banking and Trust Company, as trustee, as amended and supplemented
Mitsubishi	Mitsubishi Hitachi Power Systems Americas, Inc.
MPSC	Maryland Public Service Commission
MW	Megawatt(s)
MWh	Megawatt hour(s)
North Anna	North Anna Nuclear Power Station
NO <sub>x</sub>	Nitrogen oxide
ODEC, We, Our	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
REC	Rappahannock Electric Cooperative
RTO	Regional transmission organization
SO <sub>2</sub>	Sulfur dioxide
TEC	TEC Trading, Inc.
Wildcat Point	Wildcat Point Generation Facility
XBRL	Extensible Business Reporting Language

# OLD DOMINION ELECTRIC COOPERATIVE

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**OLD DOMINION ELECTRIC COOPERATIVE  
PART 1. FINANCIAL INFORMATION**

**ITEM 1. FINANCIAL STATEMENTS  
CONDENSED CONSOLIDATED BALANCE SHEETS**

	<b>September 30, 2014</b>	<b>December 31, 2013</b>
	(in thousands)	
	(unaudited)	
<b>ASSETS:</b>		
Electric Plant:		
Property, plant, and equipment	\$ 1,668,047	\$ 1,660,548
Less accumulated depreciation	<u>(774,868)</u>	<u>(755,288)</u>
	893,179	905,260
Nuclear fuel, at amortized cost	13,772	23,636
Construction work in progress	<u>127,610</u>	<u>36,482</u>
Net Electric Plant	<u>1,034,561</u>	<u>965,378</u>
Investments:		
Nuclear decommissioning trust	141,615	134,454
Lease deposits	98,471	96,634
Unrestricted investments and other	<u>6,841</u>	<u>24,896</u>
Total Investments	<u>246,927</u>	<u>255,984</u>
Current Assets:		
Cash and cash equivalents	35,943	51,669
Accounts receivable	6,325	12,742
Accounts receivable—deposits	-	4,400
Accounts receivable—members	85,159	88,545
Fuel, materials, and supplies	67,266	49,246
Deferred energy	27,063	-
Prepayments and other	<u>2,637</u>	<u>3,892</u>
Total Current Assets	<u>224,393</u>	<u>210,494</u>
Deferred Charges:		
Regulatory assets	84,113	87,983
Other	<u>14,182</u>	<u>10,758</u>
Total Deferred Charges	<u>98,295</u>	<u>98,741</u>
Total Assets	<u>\$ 1,604,176</u>	<u>\$ 1,530,597</u>
<b>CAPITALIZATION AND LIABILITIES:</b>		
Capitalization:		
Patronage capital	\$ 376,986	\$ 369,997
Non-controlling interest	<u>5,682</u>	<u>5,691</u>
Total Patronage capital and Non-controlling interest	382,668	375,688
Long-term debt	<u>784,330</u>	<u>749,330</u>
Total Capitalization	<u>1,166,998</u>	<u>1,125,018</u>
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	96,181	68,560
Accounts payable—members	43,252	24,998
Accrued expenses	18,518	4,991
Deferred energy	-	37,193
Total Current Liabilities	<u>186,243</u>	<u>164,034</u>
Deferred Credits and Other Liabilities:		
Asset retirement obligations	83,917	80,860
Obligations under long-term lease	83,353	79,227
Regulatory liabilities	75,578	76,940
Other	<u>8,087</u>	<u>4,518</u>
Total Deferred Credits and Other Liabilities	<u>250,935</u>	<u>241,545</u>
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	<u>\$ 1,604,176</u>	<u>\$ 1,530,597</u>

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

**OLD DOMINION ELECTRIC COOPERATIVE**

**CONDENSED CONSOLIDATED STATEMENTS OF REVENUES,  
EXPENSES, AND PATRONAGE CAPITAL (UNAUDITED)**

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>
	(in thousands)		(in thousands)	
Operating Revenues	\$ 233,904	\$ 220,393	\$ 716,331	\$ 628,729
Operating Expenses:				
Fuel	33,667	39,036	178,294	100,805
Purchased power	138,293	139,227	448,455	405,886
Deferred energy	12,704	(9,941)	(64,256)	(27,971)
Operations and maintenance	12,468	11,955	39,151	31,815
Administrative and general	9,000	11,364	31,453	32,811
Depreciation and amortization	10,476	10,586	31,480	31,795
Amortization of regulatory asset/(liability), net	1,282	1,110	4,080	2,694
Accretion of asset retirement obligations	1,019	995	3,057	2,985
Taxes, other than income taxes	1,980	2,051	6,287	6,467
Total Operating Expenses	<u>220,889</u>	<u>206,383</u>	<u>678,001</u>	<u>587,287</u>
Operating Margin	13,015	14,010	38,330	41,442
Other expense, net	(785)	(607)	(2,224)	(1,908)
Investment income	1,650	1,397	5,177	3,665
Interest charges, net	(11,537)	(12,174)	(34,305)	(35,754)
Income taxes	1	(75)	2	(96)
Net Margin including Non-controlling interest	<u>2,344</u>	<u>2,551</u>	<u>6,980</u>	<u>7,349</u>
Non-controlling interest	5	(103)	9	(169)
Net Margin attributable to ODEC	<u>2,349</u>	<u>2,448</u>	<u>6,989</u>	<u>7,180</u>
Patronage Capital - Beginning of Period	<u>374,637</u>	<u>365,156</u>	<u>369,997</u>	<u>360,424</u>
Patronage Capital - End of Period	<u>\$ 376,986</u>	<u>\$ 367,604</u>	<u>\$ 376,986</u>	<u>\$ 367,604</u>

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

**OLD DOMINION ELECTRIC COOPERATIVE**

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)**

	<b>Nine Months Ended</b>	
	<b>September 30,</b>	
	<b>2014</b>	<b>2013</b>
	(in thousands)	
<b>Operating Activities:</b>		
Net Margin including Non-controlling interest	\$ 6,980	\$ 7,349
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	31,480	31,795
Other non-cash charges	13,512	14,183
Amortization of lease obligations	4,126	3,855
Interest on lease deposits	(2,121)	(2,071)
Change in current assets	(2,562)	28,524
Change in deferred energy	(64,256)	(27,971)
Change in current liabilities	42,992	(6,012)
Change in regulatory assets and liabilities	336	(10,808)
Change in deferred charges and credits	(2,643)	565
Net Cash Provided by Operating Activities	<u>27,844</u>	<u>39,409</u>
<b>Investing Activities:</b>		
Purchases of held to maturity securities	(2,240)	(49,997)
Proceeds from sale of held to maturity securities	20,000	53,117
Increase in other investments	(4,409)	(3,676)
Electric plant additions	(91,921)	(18,772)
Net Cash Used for Investing Activities	<u>(78,570)</u>	<u>(19,328)</u>
<b>Financing Activities:</b>		
Issuance of long-term debt	-	100,000
Debt issuance costs	-	(744)
Payment of long-term debt	-	(60,535)
Draws on revolving credit facilities	222,954	-
Repayments on revolving credit facilities	(187,954)	-
Net Cash Provided by Financing Activities	<u>35,000</u>	<u>38,721</u>
Net Change in Cash and Cash Equivalents	(15,726)	58,802
Cash and Cash Equivalents - Beginning of Period	51,669	37,343
Cash and Cash Equivalents - End of Period	<u>\$ 35,943</u>	<u>\$ 96,145</u>

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

## OLD DOMINION ELECTRIC COOPERATIVE

### NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

#### 1. *General*

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. In the opinion of management, the accompanying unaudited condensed consolidated financial statements contain all adjustments, which include only normal recurring adjustments, necessary for a fair statement of our consolidated financial position as of September 30, 2014, our consolidated results of operations for the three and nine months ended September 30, 2014 and 2013, and cash flows for the nine months ended September 30, 2014 and 2013. The consolidated results of operations for the three and nine months ended September 30, 2014, are not necessarily indicative of the results to be expected for the entire year. These financial statements should be read in conjunction with the financial statements and notes thereto included in our 2013 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative and TEC. We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are eleven customer-owned electric distribution cooperatives engaged in the retail sale of power to member customers located in Virginia, Delaware, and Maryland. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which we are the primary beneficiary. We have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the consolidated assets were \$5.7 million at September 30, 2014 and December 31, 2013. The income taxes reported on our Condensed Consolidated Statement of Revenues, Expenses, and Patronage Capital relate to the tax provision for TEC. As TEC is wholly-owned by our Class A members, its equity is presented as a non-controlling interest in our consolidated financial statements.

Our rates are set periodically by a formula that was accepted for filing by FERC, but are not regulated by the respective public service commissions of the states in which our member distribution cooperatives operate. See Note 5—Other—FERC Proceeding Related to Formula Rate below.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with GAAP, the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates.

We do not have any other comprehensive income for the periods presented.

#### 2. *Fair Value Measurements*

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

The following table summarizes our financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2014 and December 31, 2013:

	<b>September 30, 2014</b>	<b>Quoted Prices in Active Markets for Identical Assets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>
		(in thousands)		
Nuclear decommissioning trust <sup>(1)(2)</sup>	\$ 141,615	\$ 44,903	\$ 96,712	\$ -
Unrestricted investments and other <sup>(3)</sup>	190	190	-	-
Total Financial Assets	<u>\$ 141,805</u>	<u>\$ 45,093</u>	<u>\$ 96,712</u>	<u>\$ -</u>
Derivatives - gas and power, net <sup>(4)</sup>	\$ 249	\$ 680	\$ (431)	\$ -
Total Financial Liabilities	<u>\$ 249</u>	<u>\$ 680</u>	<u>\$ (431)</u>	<u>\$ -</u>

  

	<b>December 31, 2013</b>	<b>Quoted Prices in Active Markets for Identical Assets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>
		(in thousands)		
Nuclear decommissioning trust <sup>(1)(2)</sup>	\$ 134,454	\$ 42,661	\$ 91,793	\$ -
Unrestricted investments and other <sup>(3)</sup>	173	173	-	-
Derivatives - gas and power, net <sup>(4)</sup>	412	412	-	-
Total Financial Assets	<u>\$ 135,039</u>	<u>\$ 43,246</u>	<u>\$ 91,793</u>	<u>\$ -</u>

<sup>(1)</sup> For additional information about our nuclear decommissioning trust see Note 4 below.

<sup>(2)</sup> Nuclear decommissioning trust includes investments that are available for sale and classified as Level 2. These Level 2 assets consist of an equity fund that attempts to replicate the return of the S&P 500, an equity fund that invests in small capitalization stocks, and an equity fund that invests in international stocks. The fair values of the investments in the nuclear decommissioning trust have been estimated using the net asset value per share.

<sup>(3)</sup> Unrestricted investments and other includes investments that are related to equity securities.

<sup>(4)</sup> Derivatives – gas and power, net represent natural gas futures contracts and purchased power contracts, which are recorded on our Condensed Consolidated Balance Sheet in deferred charges–other if an asset, or in deferred credits and other liabilities–other, if a liability. The level 2 derivatives – gas and power, net include gas and purchased power contracts valued by ACES. The gas contracts are indexed against NYMEX and the purchased power contracts are valued using observable market inputs for similar transactions. For additional information about our derivative financial instruments, see Notes 1 and 4 of the Notes to Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.

We did not have any financial assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category.

### 3. Derivatives and Hedging

We are exposed to market price risk by purchasing power to supply the power requirements of our member distribution cooperatives that are not met by our owned generation. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk. To manage this exposure, we utilize derivative instruments. See Note 1 of the Notes to Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.



Changes in the fair value of our derivative instruments accounted for at fair value are recorded as a regulatory asset or regulatory liability. The change in these accounts is included in the operating activities section of our Condensed Consolidated Statements of Cash Flows.

Excluding contracts accounted for as normal purchase/normal sale, we had the following outstanding derivative instruments:

<u>Commodity</u>	<u>Unit of Measure</u>	<u>As of</u>	<u>As of</u>
		<u>September 30, 2014</u>	<u>December 31, 2013</u>
		<u>Quantity</u>	<u>Quantity</u>
Natural gas	MMBTU	6,505,280	1,470,000
Purchased power - excess sales	MWh	111,600	-

The fair value of our derivative instruments, excluding contracts accounted for as normal purchase/normal sale, was as follows:

<u>Balance Sheet Location</u>	<u>Fair Value</u>	
	<u>As of</u>	<u>As of</u>
	<u>September 30, 2014</u>	<u>December 31, 2013</u>
	(in thousands)	
<b>Derivatives in an asset position:</b>		
Natural gas futures contracts	\$ -	\$ 412
<b>Total derivatives in an asset position</b>	<u>\$ -</u>	<u>\$ 412</u>
<b>Derivatives in a liability position:</b>		
Natural gas futures contracts	\$ 134	\$ -
Purchased power contracts - excess sales	115	-
<b>Total derivatives in a liability</b>	<u>\$ 249</u>	<u>\$ -</u>

**The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three and Nine months Ended September 30, 2014 and 2013**

<u>Derivatives Accounted for Utilizing Regulatory Accounting</u>	<u>Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of September 30,</u>		<u>Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income</u>	<u>Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Three Months Ended September 30,</u>		<u>Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Nine Months Ended September 30,</u>	
	<u>2014</u>	<u>2013</u>		<u>2014</u>	<u>2013</u>	<u>2014</u>	<u>2013</u>
	(in thousands)			(in thousands)		(in thousands)	
Natural gas futures contracts	\$ (135)	\$ (11)	Fuel	\$ (1,081)	\$ (2,344)	\$ (746)	\$ (3,031)
Purchased power contracts - excess	(115)	-	Purchased power	-	-	-	-
<b>Total</b>	<u>\$ (250)</u>	<u>\$ (11)</u>		<u>\$ (1,081)</u>	<u>\$ (2,344)</u>	<u>\$ (746)</u>	<u>\$ (3,031)</u>

Our hedging activities expose us to credit-related risks. We use hedging instruments, including forwards, futures, financial transmission rights, and options, to mitigate our power market price risks. Because we rely substantially on the use of hedging instruments, we are exposed to the risk that counterparties will default in performance of their obligations to us. Although we assess the creditworthiness of counterparties and other credit issues related to these hedging instruments, and we may require our counterparties to post collateral with us, defaults may still occur. Defaults may take the form of failure to physically deliver purchased energy or failure to pay. If this occurs, we may be forced to enter into alternative contractual arrangements or purchase energy in the forward, short-term, or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

#### 4. Investments

Investments were as follows at September 30, 2014 and December 31, 2013:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
(in thousands)						
<b>September 30, 2014</b>						
Nuclear decommissioning trust <sup>(1)</sup>						
Debt securities	Available for sale	\$ 41,333	\$ 3,114	\$ -	\$ 44,447	\$ 44,447
Equity securities	Available for sale	66,434	30,278	-	96,712	96,712
Cash and other	Available for sale	456	-	-	456	456
Total Nuclear Decommissioning Trust		<u>\$ 108,223</u>	<u>\$ 33,392</u>	<u>\$ -</u>	<u>\$ 141,615</u>	<u>\$ 141,615</u>
Lease Deposits <sup>(2)</sup>						
Government obligations	Held to maturity	\$ 98,471	\$ 5,316	\$ -	\$ 103,787	\$ 98,471
Total Lease Deposits		<u>\$ 98,471</u>	<u>\$ 5,316</u>	<u>\$ -</u>	<u>\$ 103,787</u>	<u>\$ 98,471</u>
Unrestricted investments						
Government obligations	Held to maturity	\$ 2,006	\$ -	\$ (4)	\$ 2,002	\$ 2,006
Debt securities	Held to maturity	2,440	-	(1)	2,439	2,440
Total Unrestricted Investments		<u>\$ 4,446</u>	<u>\$ -</u>	<u>\$ (5)</u>	<u>\$ 4,441</u>	<u>\$ 4,446</u>
Other						
Equity securities	Trading	\$ 146	\$ 44	\$ -	\$ 190	\$ 190
Non-marketable equity investments	Equity	2,205	1,833	-	4,038	2,205
Total Other		<u>\$ 2,351</u>	<u>\$ 1,877</u>	<u>\$ -</u>	<u>\$ 4,228</u>	<u>\$ 2,395</u>
						<u>\$ 246,927</u>
<b>December 31, 2013</b>						
Nuclear decommissioning trust <sup>(1)</sup>						
Debt securities	Available for sale	\$ 40,352	\$ 1,719	\$ -	\$ 42,071	\$ 42,071
Equity securities	Available for sale	62,293	29,500	-	91,793	91,793
Cash and other	Available for sale	590	-	-	590	590
Total Nuclear Decommissioning Trust		<u>\$ 103,235</u>	<u>\$ 31,219</u>	<u>\$ -</u>	<u>\$ 134,454</u>	<u>\$ 134,454</u>
Lease Deposits <sup>(2)</sup>						
Government obligations	Held to maturity	\$ 96,634	\$ 5,676	\$ -	\$ 102,310	\$ 96,634
Total Lease Deposits		<u>\$ 96,634</u>	<u>\$ 5,676</u>	<u>\$ -</u>	<u>\$ 102,310</u>	<u>\$ 96,634</u>
Unrestricted investments						
Government obligations	Held to maturity	\$ 20,174	\$ 1	\$ -	\$ 20,175	\$ 20,174
Debt securities	Held to maturity	2,200	-	(4)	2,196	2,200
Total Unrestricted Investments		<u>\$ 22,374</u>	<u>\$ 1</u>	<u>\$ (4)</u>	<u>\$ 22,371</u>	<u>\$ 22,374</u>
Other						
Equity securities	Trading	\$ 131	\$ 42	\$ -	\$ 173	\$ 173
Non-marketable equity investments	Equity	2,349	1,735	-	4,084	2,349
Total Other		<u>\$ 2,480</u>	<u>\$ 1,777</u>	<u>\$ -</u>	<u>\$ 4,257</u>	<u>\$ 2,522</u>
						<u>\$ 255,984</u>

<sup>(1)</sup> Investments in the nuclear decommissioning trust are restricted for the use of funding our share of the asset retirement obligations of the future decommissioning of North Anna. See Note 3 of the Notes to Consolidated Financial Statements in our 2013 Annual Report on Form 10-K. Unrealized gains and losses related to assets held in the nuclear decommissioning trust are deferred as a regulatory asset or liability.

<sup>(2)</sup> Investments in lease deposits are restricted for the use of funding our future lease obligations. See Note 8 of the Notes to Consolidated Financial Statements in our 2013 Annual Report on Form 10-K.

Our investments by classification at September 30, 2014 and December 31, 2013, were as follows:

<u>Description</u>	<u>September 30, 2014</u>		<u>December 31, 2013</u>	
	<u>Cost</u>	<u>Carrying Value</u>	<u>Cost</u>	<u>Carrying Value</u>
	(in thousands)			
Available for sale	\$ 108,223	\$ 141,615	\$ 103,235	\$ 134,454
Held to maturity	102,917	102,917	119,008	119,008
Equity	2,205	2,205	2,349	2,349
Trading	146	190	131	173
	<u>\$ 213,491</u>	<u>\$ 246,927</u>	<u>\$ 224,723</u>	<u>\$ 255,984</u>

Contractual maturities of debt securities at September 30, 2014, were as follows:

<u>Description</u>	<u>Less than</u>	<u>1-5 years</u>	<u>5-10 years</u>	<u>More than</u>	<u>Total</u>
	<u>1 year</u>			<u>10 years</u>	
	(in thousands)				
Available for sale <sup>(1)</sup>	\$ -	\$ -	\$ 44,447	\$ -	\$ 44,447
Held to maturity	1,756	101,081	80	-	102,917
	<u>\$ 1,756</u>	<u>\$ 101,081</u>	<u>\$ 44,527</u>	<u>\$ -</u>	<u>\$ 147,364</u>

<sup>(1)</sup> The contractual maturities of available for sale debt securities are measured using the effective duration of the bond fund within the nuclear decommissioning trust.

## 5. *Other*

### *Margin Stabilization*

Margin Stabilization allows us to review our actual demand-related costs of service and demand revenue and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formula rate allows us to recover and refund amounts utilizing Margin Stabilization. Pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order (see "FERC Proceeding Related to Formula Rate" below), effective January 1, 2014:

- At year end, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 20% of our actual total interest charges, our board of directors may approve that, utilizing Margin Stabilization, revenues will be reduced by the amount of such excess margins, or that such excess margins will be retained as an additional equity contribution. For year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 20% of our actual total interest charges, utilizing Margin Stabilization, revenues will be reduced by the amount of such excess margins.
- At year end and for year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 10% but less than 20% of our actual total interest charges, no adjustment is required.
- At year end and for year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals less than 10% of our actual total interest charges, utilizing Margin Stabilization, revenues will be increased to produce a net margin attributable to ODEC, excluding any budgeted additional equity contributions, equal to 10% of our actual total interest charges.

For the three and nine months ended September 30, 2014, we recorded a reduction in operating revenues of \$40,100 and \$1.9 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges. For the three and nine months ended September 30, 2013, we recorded a reduction to operating revenues of \$2.3 million and \$10.6 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.

### *Three and Nine Months Ended September 2014 Results and the Impact on Deferred Energy*

Deferred energy expense represents the difference between energy revenues, which are based upon energy rates approved by our board of directors, and energy expenses, which are based upon actual energy costs incurred. In the three months ended September 30, 2014, we over-collected energy costs from our member distribution cooperatives by \$12.7 million and for the nine months ended September 30, 2014, we under-collected energy costs from our member distribution cooperatives by \$64.3 million. As a result, our deferred energy balance changed from an over-collection of \$37.2 million at December 31, 2013, to an under-collection of \$27.1 million at September 30, 2014. This under-collection was driven by first quarter 2014 results when the entire mid-Atlantic region experienced extremely cold weather, which increased our energy sales in MWh to our member distribution cooperatives 10.2% over the expected requirements, and which had a significant effect on our fuel and purchased power costs. To address the under-collection of energy costs, we increased our total energy rate 11.8% effective April 1, 2014, and an additional 2.4% effective October 1, 2014.

#### *Wildcat Point Generation Facility*

On April 23, 2013, we announced our intention to seek approval to develop and construct a 1,000 MW natural gas-fueled generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to obtainment of necessary governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor under a fixed price contract. Site preparation and engineering activities are in process and we anticipate permanent construction will begin in late 2014, and the facility will become operational in mid-2017. We currently anticipate that the project cost will be approximately \$790.0 million, including financing costs.

Wildcat Point will consist of two combustion turbines, two heat recovery steam generators and one steam turbine generator. Mitsubishi will supply the combustion turbines and Alstom will supply the heat recovery steam generators and the steam turbine generator. Beginning in June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. For the nine months ended September 30, 2014 and 2013, we expensed \$4.1 million and \$5.8 million, respectively, of non-capital costs related to Wildcat Point. As of September 30, 2014, we capitalized progress payments for major equipment, EPC payments, emission reduction credits, and land and land rights totaling \$76.2 million, which are recorded in construction work in progress.

#### *FERC Proceeding Related to Formula Rate*

On September 30, 2013, we filed with FERC to revise our cost-based formula rate to more closely align our cost recovery from our member distribution cooperatives with the methodologies used by PJM to allocate costs to us. On November 8, 2013, Bear Island, a customer of REC, filed a motion to intervene, protest, and request for hearing. On December 2, 2013, FERC issued its order accepting the proposed revisions for filing to become effective January 1, 2014, subject to refund, and establishing hearing and settlement procedures. Settlement discussions have been terminated and a litigation schedule has been set with a hearing date of December 9, 2014. The presiding judge of the proceeding referred the parties to dispute resolution procedures with the assistance of FERC Dispute Resolution Service; however, dispute resolution procedures have been terminated and the hearing procedures continue.

#### *Recovery of Costs from PJM*

On June 23, 2014, we filed a petition at FERC seeking recovery from PJM of approximately \$14.9 million of unreimbursed costs, which were incurred during the first quarter of 2014 related to the dispatch of our combustion turbine generating facilities. The results of our petition cannot currently be determined and we have not recorded a receivable related to this matter.

### *Revolving Credit Facility*

We currently maintain a \$500.0 million, five-year revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019. At September 30, 2014, we had \$35.0 million in borrowings outstanding under this facility, which are recorded in long-term debt. Additionally, at September 30, 2014, we had a letter of credit in the amount of \$7.0 million outstanding. At December 31, 2013, we did not have any borrowings or letters of credit outstanding under this facility.

### *Long-term debt*

We currently anticipate that we will issue long-term debt in the first quarter of 2015 to fund capital expenditures related to the construction of Wildcat Point.

## OLD DOMINION ELECTRIC COOPERATIVE

### ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

#### Caution Regarding Forward-looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, demand for energy, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, general credit and capital market conditions, weather conditions, the cost of commodities used in our industry, and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward-looking statements as a result of these and other factors. Any forward-looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

#### Critical Accounting Policies

As of September 30, 2014, there have been no significant changes in our critical accounting policies as disclosed in our 2013 Annual Report on Form 10-K. These policies include the accounting for rate regulation, deferred energy, margin stabilization, accounting for asset retirement and environmental obligations, and accounting for derivatives and hedging.

#### Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of ODEC and TEC. See Note 1—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

#### Overview

We are a not-for-profit power supply cooperative owned entirely by our eleven Class A member distribution cooperatives and a Class B member, TEC. We supply our member distribution cooperatives' energy and demand requirements through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases. We also supply the transmission services necessary to deliver this power to our member distribution cooperatives.

Our results for the nine months ended September 30, 2014, were still significantly impacted by the extremely cold weather experienced by the entire mid-Atlantic region during the first quarter of 2014, which increased energy sales and fuel and purchased power expense, and changed our deferred energy balance from an over-collection to an under-collection. Our average energy cost increased 12.6%, primarily driven by a \$77.5 million increase in fuel expense and a \$42.6 million increase in purchased power expense. The increase in fuel expense was primarily impacted by a 73.7% increase in the dispatch of our combustion turbine facilities as well as a 192.1% increase in the average cost of fuel for these facilities. The increase in purchased power expense was driven by a 6.3% increase in the average cost of purchased energy and a 2.9% increase in the volume of purchased energy. In the three months ended September 30, 2014, we over-collected energy costs from our member distribution cooperatives by \$12.7 million, and for the nine months ended September 30, 2014, we under-collected energy costs from our member distribution cooperatives by \$64.3 million. Any over-or under-collection of energy costs is recorded as deferred energy expense. As a result, our deferred energy balance, which represents the cumulative difference between energy revenues and energy expenses, changed from an over-collection of \$37.2 million at December 31, 2013, to an under-collection of \$27.1 million at September 30, 2014. To address the under-collection of energy costs, we increased our total energy rate 11.8% effective April 1, 2014, and an additional 2.4% effective October 1, 2014. For further discussion on deferred energy, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Deferred Energy" in Item 7 of our 2013 Annual Report on Form 10-K.

## **Wildcat Point Generation Facility**

On April 23, 2013, we announced our intention to seek approval to develop and construct a 1,000 MW natural gas-fueled generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to obtainment of necessary governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor under a fixed price contract. Site preparation and engineering activities are in process and we anticipate permanent construction will begin in late 2014, and the facility will become operational in mid-2017. We currently anticipate that the project cost will be approximately \$790.0 million, including financing costs.

Wildcat Point will consist of two combustion turbines, two heat recovery steam generators and one steam turbine generator. Mitsubishi will supply the combustion turbines and Alstom will supply the heat recovery steam generators and the steam turbine generator. Beginning in June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. For the nine months ended September 30, 2014 and 2013, we expensed \$4.1 million and \$5.8 million, respectively, of non-capital costs related to Wildcat Point. As of September 30, 2014, we capitalized progress payments for major equipment, EPC payments, emission reduction credits, and land and land rights totaling \$76.2 million, which are recorded in construction work in progress.

## **Factors Affecting Results**

### **Formula Rate**

Our power sales are comprised of two power products – energy and demand. Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as demand.

The rates we charge our member distribution cooperatives for sales of energy and demand are determined by a formula rate accepted by FERC which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

The formula rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited minor exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval.

Energy costs, which are primarily variable costs, such as nuclear, coal, and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate rates, the base energy rate and the energy adjustment rate. Through December 31, 2013, the base energy rate was a fixed rate that required FERC approval prior to adjustment. To the extent the base energy rate over- or under-collected our energy costs, we refunded or collected the difference through an energy adjustment rate. We reviewed our energy costs at least every six months to determine whether the base energy rate and the current energy adjustment rate together were recovering our actual and anticipated energy costs, and revised the energy adjustment rate accordingly. Effective January 1, 2014, pursuant to FERC's acceptance of revisions to the formula rate as issued in FERC's December 2, 2013 order; the base energy rate is no longer a fixed rate that requires FERC approval prior to adjustment. The base energy rate now will be developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the energy adjustment rate will be zero. With board approval, we can revise the energy adjustment rate at any time during the year if it becomes apparent that the combined base energy rate and the current energy adjustment rate are over-collecting or under-collecting our actual and anticipated energy costs. See "FERC Proceeding Related to Formula Rate" in Part II, Item 1 below.

Demand costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. The formula rate allows us to change the actual demand rates we charge as our demand-related costs change, without FERC approval,

with the exception of decommissioning cost, which is a fixed number in the formula rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, depreciation studies are required to be filed with FERC for its approval if they would result in a change in our depreciation rates. Through December 31, 2013, we collected our total demand costs through a single demand rate. Effective January 1, 2014, pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order, we now collect our total demand costs through the following three separate rates:

- Transmission service rate – designed to collect transmission-related and distribution-related costs;
- RTO capacity service rate – a proxy rate based on capacity prices in PJM which PJM allocates to ODEC and all other RTO members; and
- Remaining owned capacity service rate – recovers all remaining demand costs not billed and/or recovered under the transmission service and RTO capacity service rates.

As stated above, our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. We establish our demand rates to produce a net margin attributable to ODEC equal to 20% of our budgeted total interest charges plus additional equity contributions approved by our board of directors. Through December 31, 2013, utilizing Margin Stabilization, we adjusted our operating revenues to reflect actual demand costs incurred, including a net margin attributable to ODEC equal to 20% of actual interest charges plus additional equity contributions approved by our board of directors. Effective January 1, 2014:

- At year end, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 20% of our actual total interest charges, our board of directors may approve that, utilizing Margin Stabilization, revenues will be reduced by the amount of such excess margins, or that such excess margins will be retained as an additional equity contribution. For year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 20% of our actual total interest charges, utilizing Margin Stabilization, revenues will be reduced by the amount of such excess margins.
- At year end and for year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 10% but less than 20% of our actual total interest charges, no adjustment is required.
- At year end and for year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals less than 10% of our actual total interest charges, utilizing Margin Stabilization, revenues will be increased to produce a net margin attributable to ODEC, excluding any budgeted additional equity contributions, equal to 10% of our actual total interest charges.

For the three and nine months ended September 30, 2014, we recorded a reduction in operating revenues of \$40,100 and \$1.9 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges. For the three and nine months ended September 30, 2013, we recorded a reduction in operating revenues of \$2.3 million and \$10.6 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.



## Weather

Weather is one factor that affects the demand for electricity. Weather also plays a role in the price of market energy through its effects on the market prices for fuel, particularly natural gas. Heating degree days are a measurement tool used to quantify the need to utilize heat for a building, and cooling degree days are a measurement tool used to quantify the need to utilize cooling for a building. The heating and cooling degree data is compiled utilizing various weather stations. Weather stations can be added or changed during the year, which may result in updates to previously reported data. The heating degree days and cooling degree days for the three and nine months ended September 30, 2014 and 2013, were as follows:

	Three Months Ended			Nine Months Ended		
	September 30,		%	September 30,		%
	2014	2013		2014	2013	
Heating degree days	-	-	-	2,607	2,275	14.6
Cooling degree days	744	849	(12.4)	1,064	1,131	(5.9)

## Power Supply Resources

We provide power to our members through a combination of our interests in Clover, a coal-fired generating facility; North Anna, a nuclear power station; our three combustion turbine facilities – Louisa, Marsh Run, and Rock Springs; distributed generation facilities; and physically-delivered forward power purchase contracts and spot market energy purchases. Our energy supply resources for the three and nine months ended September 30, 2014 and 2013, were as follows:

	Three Months Ended				Nine Months Ended			
	September 30,				September 30,			
	2014		2013		2014		2013	
	(in MWh and percentages)				(in MWh and percentages)			
<b>Generated:</b>								
Clover	685,719	21.0%	742,442	22.2%	1,996,626	19.8%	2,186,994	22.4%
North Anna	423,734	13.0	427,541	12.8	1,399,014	13.8	1,275,663	13.1
Louisa	34,504	1.1	49,027	1.5	181,041	1.8	86,595	0.9
Marsh Run	93,499	2.8	93,564	2.8	342,820	3.4	158,048	1.6
Rock Springs	23,399	0.7	83,799	2.5	73,521	0.7	99,260	1.0
Distributed Generation	176	-	405	-	2,168	-	439	-
Total Generated	1,261,031	38.6	1,396,778	41.8	3,995,190	39.5	3,806,999	39.0
<b>Purchased:</b>								
Other than renewable:								
Long-term and short-term	1,620,616	49.6	1,254,385	37.5	4,710,558	46.6	4,287,727	44.0
Spot market	259,684	7.9	586,920	17.6	872,854	8.6	1,130,640	11.6
Total Other than renewable	1,880,300	57.5	1,841,305	55.1	5,583,412	55.2	5,418,367	55.6
Renewable <sup>(1)</sup>	127,748	3.9	102,207	3.1	538,059	5.3	530,291	5.4
Total Purchased	2,008,048	61.4	1,943,512	58.2	6,121,471	60.5	5,948,658	61.0
Total Available Energy	3,269,079	100.0%	3,340,290	100.0%	10,116,661	100.0%	9,755,657	100.0%

<sup>(1)</sup> Related to our contracts from renewable facilities from which we purchase renewable energy credits. We sell these renewable energy credits to our member distribution cooperatives and non-members.

## Generating Facilities

Our operating expenses, and consequently our rates to our member distribution cooperatives, are significantly affected by the operations of our baseload generating facilities, Clover and North Anna. Baseload generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs. Nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run, and Rock Springs. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility; however, they are more expensive to operate and, as a result, are dispatched only when the market price of energy makes their operation economical or when their operation is required by PJM for system reliability purposes. For further discussion on PJM, see “Business—Power Supply Resources—PJM” in Item 1 of our 2013 Annual Report on Form 10-K. Owners of power plants incur the fixed costs of these facilities whether or not the units operate.

Our generating facilities are under dispatch control of PJM. Typically, nuclear facilities are almost always dispatched and coal-fired and combustion turbine facilities are dispatched based upon economic factors including the market price of energy, and to meet reliability requirements. The operational availability of our owned generating resources for the three and nine months ended September 30, 2014 and 2013, was as follows:

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>
	Clover	92.6%	96.5%	83.8%
North Anna	87.0	87.5	95.4	87.3
Louisa	100.0	94.4	97.5	97.6
Marsh Run	100.0	99.4	98.8	99.2
Rock Springs	99.4	99.9	97.6	98.7

The output of Clover and North Anna for the three and nine months ended September 30, 2014 and 2013, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>
	Clover	72.0%	77.8%	70.5%
North Anna	87.4	88.0	97.4	88.7

The scheduled and unscheduled outages for Clover and North Anna for the three and nine months ended September 30, 2014 and 2013, were as follows:

	<b>Clover</b>				<b>North Anna</b>			
	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>		<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>
	(in days)				(in days)			
Scheduled	6.5	-	72.1	15.7	24.0	23.0	24.0	55.5
Unscheduled	7.2	6.5	16.5	6.5	-	-	1.3	14.1
Total	<u>13.7</u>	<u>6.5</u>	<u>88.6</u>	<u>22.2</u>	<u>24.0</u>	<u>23.0</u>	<u>25.3</u>	<u>69.6</u>

North Anna Unit 2 began a scheduled refueling and maintenance outage on September 7, 2014, which ended on October 10, 2014.

### **Sales to Member Distribution Cooperatives**

Revenues from sales to our member distribution cooperatives are a function of our formula rate for sales of power and sales of renewable energy credits to our member distribution cooperatives, and our member distribution cooperatives' customers' requirements for power. Our formula rate is based on our cost of service in meeting these requirements. See "Factors Affecting Results—Formula Rate" above.

### **Sales to TEC**

In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which ODEC is the primary beneficiary. The financial statements of TEC are consolidated and the intercompany balances are eliminated in consolidation. TEC's sales to third parties are reflected as non-member revenues; however, in 2014 and 2013, TEC had no sales to third parties.

## Sales to Non-members

Sales to non-members consist of sales of excess purchased and generated energy and sales of renewable energy credits. We primarily sell excess energy to PJM at the prevailing market price at the time of sale. Excess energy is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, and changes in market conditions. Renewable energy credits that are not sold to our member distribution cooperatives are sold to non-members.

## Results of Operations

### Operating Revenues

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the three and nine months ended September 30, 2014 and 2013, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)		(in thousands)	
Revenues from sales to:				
Member distribution cooperatives				
Energy revenues <sup>(1)</sup>	\$ 147,770	\$ 124,359	\$ 436,414	\$ 372,318
Demand revenues	80,837	80,108	243,284	229,070
Total revenues from sales to member distribution cooperatives	228,607	204,467	679,698	601,388
Non-members <sup>(2)</sup>	5,297	15,926	36,633	27,341
Total operating revenues	<u>\$ 233,904</u>	<u>\$ 220,393</u>	<u>\$716,331</u>	<u>\$ 628,729</u>
Average cost of energy to member distribution cooperatives (per MWh)	\$ 47.61	\$ 40.09	\$ 45.43	\$ 40.33
Average cost of demand to member distribution cooperatives (per MWh)	26.04	25.82	25.32	24.82
Average total cost to member distribution cooperatives (per MWh)	<u>\$ 73.65</u>	<u>\$ 65.91</u>	<u>\$ 70.75</u>	<u>\$ 65.15</u>

<sup>(1)</sup> Includes sales of renewable energy credits of \$0.8 million and \$1.3 million, for the three and nine months ended September 30, 2014, respectively, and that were immaterial for the three and nine months ended September 30, 2013.

<sup>(2)</sup> There were no sales of renewable energy credits for the three months ended September 30, 2014. Includes sales of renewable energy credits of \$3.7 million for the nine months ended September 30, 2014, and \$4.2 million and \$6.1 million for the three and nine months ended September 30, 2013, respectively.

Our energy sales in MWh to our member distribution cooperatives and non-members for the three and nine months ended September 30, 2014 and 2013, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	3,103,902	3,102,068	9,607,339	9,230,740
Non-members	153,614	216,928	449,010	483,055
Total energy sales	<u>3,257,516</u>	<u>3,318,996</u>	<u>10,056,349</u>	<u>9,713,795</u>

Our energy sales in MWh to our member distribution cooperatives for the three months ended September 30, 2014, were relatively flat as compared to the same period in 2013. For the nine months ended September 30, 2014, MWh sales were 4.1% higher, as compared to the same period in 2013. In the first quarter of 2014, the entire mid-Atlantic region experienced extremely cold weather.

Our energy sales in MWh to non-members for the three and nine months ended September 30, 2014, were 29.2% and 7.0% lower, respectively, as compared to the same periods in 2013 as the result of the decrease in the volume of excess purchased and generated energy.

Total revenues from sales to our member distribution cooperatives for the three and nine months ended September 30, 2014, increased \$24.1 million, or 11.8%, and \$78.3 million, or 13.0%, respectively, as compared to the same periods in 2013, primarily due to net increases in our total energy rate. Our average cost of energy to member distribution cooperatives per MWh increased 18.8% and 12.6%, for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013.

The average total cost to member distribution cooperatives is affected by changes in our revenues as well as sales volumes. Our average total cost to member distribution cooperatives per MWh for the three and nine months ended September 30, 2014, was 11.7% and 8.6% higher, respectively, as compared to the same periods in 2013, primarily as a result of increases in our total energy rate. There was also an increase in demand costs related to purchased transmission and capacity due to increases in charges from PJM, as well as increased demand-related operations and maintenance expense related to the scheduled maintenance outages at Clover in 2014 as compared to 2013.

The following table summarizes the changes to our total energy rate which were implemented to address the differences in our realized as well as projected energy costs:

<u>Effective Date of Rate Change</u>	<u>% Change</u>
April 1, 2013	(2.4)
October 1, 2013	4.7
January 1, 2014	0.5
April 1, 2014	11.8
October 1, 2014	2.4

Non-member revenue for the three months ended September 30, 2014, decreased \$10.6 million, or 66.7%, as compared to the same period in 2013, due to a 54.9% decrease in revenue from sales of excess energy and a 100.0% decrease in revenue from sales of renewable energy credits. The decrease in revenue from sales of excess energy was due to a 29.2% decrease in the volume of excess energy sales and a 36.4% decrease in the average price of excess energy. Non-member revenue for the nine months ended September 30, 2014, increased \$9.3 million, or 34.0%, as compared to the same period in 2013, due to a 67.3% increase in the average price of excess energy.

### Operating Expenses

The following is a summary of the components of our operating expenses for the three and nine months ended September 30, 2014 and 2013:

	<u>Three Months Ended</u> <u>September 30,</u>		<u>Nine Months Ended</u> <u>September 30,</u>	
	<u>2014</u>	<u>2013</u>	<u>2014</u>	<u>2013</u>
	<u>(in thousands)</u>		<u>(in thousands)</u>	
Fuel	\$ 33,667	\$ 39,036	\$ 178,294	\$ 100,805
Purchased power	138,293	139,227	448,455	405,886
Deferred energy	12,704	(9,941)	(64,256)	(27,971)
Operations and maintenance	12,468	11,955	39,151	31,815
Administrative and general	9,000	11,364	31,453	32,811
Depreciation and amortization	10,476	10,586	31,480	31,795
Amortization of regulatory asset/(liability), net	1,282	1,110	4,080	2,694
Accretion of asset retirement obligations	1,019	995	3,057	2,985
Taxes, other than income taxes	1,980	2,051	6,287	6,467
Total Operating Expenses	<u>\$ 220,889</u>	<u>\$ 206,383</u>	<u>\$ 678,001</u>	<u>\$ 587,287</u>

Our operating expenses are comprised of the costs that we incur to generate and purchase power to meet the needs of our member distribution cooperatives, and the costs associated with any sales of power to non-members. Our energy costs generally are variable and include the energy portion of our purchased power expense, fuel expense, and the variable portion of operations and maintenance expense. Our demand costs generally are fixed and include the fixed portion of operations and maintenance expense, administrative and general, and depreciation and amortization expenses, as well as the capacity portion of our purchased power expense. Additionally, all non-operating expenses and income items, including interest charges, net and investment income, are components of our demand costs. See “Factors Affecting Results—Formula Rate” above.

Total operating expenses increased \$14.5 million, or 7.0%, and \$90.7 million, or 15.4%, for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended September 30, 2014 was primarily due to the increase in deferred energy. The increase for the nine months ended September 30, 2014, was primarily due to increases in fuel and purchased power, partially offset by the decrease in deferred energy.

- Fuel expense increased \$77.5 million, or 76.9%, for the nine months ended September 30, 2014, as compared to the same period in 2013. This increase was primarily driven by the 73.7% increase in the dispatch of our

combustion turbine facilities as well as the 192.1% increase in the average cost of fuel for our combustion turbine facilities.

- Purchased power expense, which includes the cost of purchased energy, capacity, and transmission, increased \$42.6 million, or 10.5%, for the nine months ended September 30, 2014, as compared to the same period in 2013. The average cost of purchased energy increased 6.3% and the volume of purchased energy increased 2.9%.
- Deferred energy expense increased \$22.6 million for the three months ended September 30, 2014, as compared to the same period in 2013. Deferred energy expense decreased \$36.3 million for the nine months ended September 30, 2014, as compared to the same period in 2013. For the three months ended September 30, 2014, we over-collected \$12.7 million and for nine months ended September 30, 2014, we under-collected \$64.3 million. Deferred energy expense represents the difference between energy revenues and energy expenses.

## Other Items

### Investment Income

Investment income increased for the three and nine months ended September 30, 2014, by \$0.3 million, or 18.1%, and \$1.5 million, or 41.3%, as compared to the same periods in 2013, primarily due to higher income earned on our nuclear decommissioning trust.

### Interest Charges, Net

The major components of interest charges, net for the three and nine months ended September 30, 2014 and 2013, were as follows:

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2014</b>	<b>2013</b>	<b>2014</b>	<b>2013</b>
	(in thousands)		(in thousands)	
Total interest charges	\$ (11,748)	\$ (12,237)	\$ (34,945)	\$ (35,900)
Allowance for borrowed funds used during construction	211	63	640	146
Interest charges, net	<u>\$ (11,537)</u>	<u>\$ (12,174)</u>	<u>\$ (34,305)</u>	<u>\$ (35,754)</u>

Interest charges, net decreased for the three and nine months ended September 30, 2014, by \$0.6 million, or 5.2%, and \$1.4 million, or 4.1%, respectively, as compared to the same periods in 2013, as a result of the decrease in total interest charges due to scheduled principal payments, and the increase in allowance for borrowed funds used during construction.

### Net Margin Attributable to ODEC

Net margin attributable to ODEC, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, decreased for the three and nine months ended September 30, 2014, by \$0.1 million, or 4.0%, and \$0.2 million, or 2.7%, respectively, as compared to the same periods in 2013.

## Financial Condition

The principal changes in our financial condition from December 31, 2013 to September 30, 2014, were caused by the increase in construction work in progress, the change in deferred energy, the increases in long-term debt, accounts payable, accounts payable—members, fuel, materials, and supplies, and accrued expenses, partially offset by the decrease in unrestricted investments and other.

- Construction work in progress increased \$91.1 million primarily due to expenditures related to Wildcat Point and nuclear fuel.
- Deferred energy changed \$64.3 million as a result of the under-collection of our energy costs in 2014. The deferred energy balance changed from a \$37.2 million liability (over-collection) at December 31, 2013 to a \$27.1 million asset (under-collection) at September 30, 2014.

- Long-term debt increased \$35.0 million due to outstanding borrowings under our revolving credit facility.
- Accounts payable increased \$27.6 million due to increased payables related to our ownership interests in Clover and North Anna, and payables related to Wildcat Point.
- Accounts payable—members increased \$18.3 million due to the increase in member prepayments offset by the decrease in amounts owed to our member distribution cooperatives under Margin Stabilization.
- Fuel, materials, and supplies increased \$18.0 million primarily due to the increase in coal and diesel fuel balances.
- Accrued expenses increased \$13.5 million primarily as a result of accrued interest on long-term debt.
- Unrestricted investments and other decreased \$18.1 million primarily as a result of the liquidation of temporary investments.

## **Liquidity and Capital Resources**

### **Sources**

Cash generated by our operations, periodic borrowings under our credit facility, and occasional issuances of long-term indebtedness provide our sources of liquidity and capital.

### **Operations**

During the first nine months of 2014 and 2013, our operating activities provided cash flows of \$27.8 million and \$39.4 million respectively. Operating activities in 2014 were primarily impacted by the following:

- Deferred energy changed \$64.3 million due to the under-collection of energy costs in 2014. To address the under-collection of energy costs, we increased our total energy rate 11.8% effective April 1, 2014, and an additional 2.4% effective October 1, 2014.
- Current liabilities changed \$43.0 million due to the \$18.3 million increase in accounts payable—members, the \$13.5 million increase in accrued liabilities, and the \$11.2 million increase in accounts payable.

### **Revolving Credit Facility**

We currently maintain a \$500.0 million, five-year revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019. At September 30, 2014, we had \$35.0 million in borrowings outstanding under this facility, which are recorded in long-term debt. Additionally, at September 30, 2014, we had a letter of credit in the amount of \$7.0 million outstanding. At December 31, 2013, we did not have any borrowings outstanding under this facility.

### **Financings**

We fund the portion of our capital expenditures that we are not able to fund from operations through borrowings under our revolving credit facility and financings in the debt capital markets. These capital expenditures consist primarily of the costs related to the development, construction, acquisition, or improvement of our owned generating facilities. We currently anticipate that we will issue long-term debt in the first quarter of 2015 to fund expenditures related to the construction of Wildcat Point.

### **Uses**

Our uses of liquidity and capital relate to funding our working capital needs, investment activities, and financing activities. Substantially all of our investment activities relate to capital expenditures in connection with our generating facilities. We expect that cash flow from our operations, borrowings under our revolving credit facility, and financings in the debt capital markets will be sufficient to meet our currently anticipated future operational and capital requirements.

## Contractual Obligations

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our generating facilities, power purchases for capacity and energy, the financing of our operations, and other matters. On April 8, 2014, we received a Final Order granting approval of the Wildcat Point CPCN from the MPSC and on June 2, 2014, we selected White Oak Power Constructors as the EPC contractor. As a result of these events, we had a change to our contractual obligations, specifically with respect to construction obligations. In our SEC Form 10-Q for the quarterly period ended June 30, 2014, we disclosed an updated contractual obligations table as follows:

	Payments due by Period				2019 and Thereafter
	Total	2014	2015-2016	2017-2018	
			(in millions)		
Long-term indebtedness	\$ 1,399.0	\$ 71.0	\$ 137.0	\$ 130.4	\$ 1,060.6
Power purchase obligations	1,191.5	212.0	387.6	332.1	259.8
Asset retirement obligations	389.4	-	-	-	389.4
Operating lease obligations	112.2	0.5	1.0	1.5	109.2
Construction obligations	575.7	92.4	464.2	19.1	-
Total	<u>\$ 3,667.8</u>	<u>\$ 375.9</u>	<u>\$ 989.8</u>	<u>\$ 483.1</u>	<u>\$ 1,819.0</u>

See “Liquidity and Capital Resources—Contractual Obligations” in Item 7 of our 2013 Annual Report on Form 10-K. We expect to fund these obligations with cash flow from operations, borrowings under our syndicated credit facility, and financings in the debt capital markets.

### Long-term Indebtedness

At December 31, 2013, all of our long-term indebtedness was issued under the Indenture. Long-term indebtedness includes both the principal of and interest on long-term indebtedness, long-term indebtedness due within one year and unamortized discounts and premiums relating to long-term indebtedness.

### Power Purchase Obligations

As part of our power supply strategy, we entered into a number of agreements for the purchase of capacity or energy, or both, in order to meet our member distribution cooperatives’ requirements.

### Asset Retirement Obligations

We account for our asset retirement obligations in accordance with Accounting for Asset Retirement and Environmental Obligations which requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. A significant portion of our asset retirement obligations relates to the future decommissioning of North Anna by 2059.

### Operating Lease Obligations

Our obligation described above primarily relates to our portion of the Clover Unit 1 purchase option price at the end of the term of the leaseback that will be satisfied by our investment in United States Treasury securities.

### Construction Obligations

This includes payments related to major equipment purchase contracts for Wildcat Point as well as EPC contractor payments. Wildcat Point will consist of two combustion turbines, two heat recovery steam generators, and one steam turbine generator. Mitsubishi will supply the combustion turbines and Alstom will supply the heat recovery steam generators and the steam turbine generator.

### **ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

No material changes occurred in our exposure to market risk during the third quarter of 2014.

### **ITEM 4. CONTROLS AND PROCEDURES**

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely matter. We have established a Disclosure Assessment Committee comprised of members from senior and middle management to assist in this evaluation. In the third quarter of 2014, we implemented a new fixed asset system. Other than the new fixed asset system, there have been no material changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the past fiscal quarter.



## OLD DOMINION ELECTRIC COOPERATIVE

### PART II. OTHER INFORMATION

#### ITEM 1. LEGAL PROCEEDINGS

##### **FERC Proceeding Related to Formula Rate**

On September 30, 2013, we filed with FERC to revise our cost-based formula rate to more closely align our cost recovery from our member distribution cooperatives with the methodologies used by PJM to allocate costs to us. On November 8, 2013, Bear Island, a customer of REC, filed a motion to intervene, protest, and request for hearing. On December 2, 2013, FERC issued its order accepting the proposed revisions for filing to become effective January 1, 2014, subject to refund, and establishing hearing and settlement procedures. Settlement discussions have been terminated and a litigation schedule has been set with a hearing date of December 9, 2014. The presiding judge of the proceeding referred the parties to dispute resolution procedures with the assistance of FERC Dispute Resolution Service; however, dispute resolution procedures have been terminated and the hearing procedures continue.

##### **Other Matters**

Other than legal proceedings arising out of the ordinary course of business, which management believes will not have a material adverse impact on our results of operations or financial condition, there is no other litigation pending or threatened against us.

#### ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in "Risk Factors" in Part I, Item 1A of our 2013 Annual Report on Form 10-K, which could affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

#### ITEM 5. OTHER INFORMATION

##### *Recovery of Costs from PJM*

On June 23, 2014, we filed a petition at FERC seeking recovery from PJM of approximately \$14.9 million of unreimbursed costs, which were incurred during the first quarter of 2014 related to the dispatch of our combustion turbine generating facilities. The results of our petition cannot currently be determined.

##### *Clean Power Plan*

On June 2, 2014, the EPA proposed emission guidelines for CO<sub>2</sub> from existing electric utility generating units under 111(d) of the Clean Air Act. This proposal, referred to as the Clean Power Plan, requires that each state develop, submit, and implement a plan to achieve the interim and final state-specific goals detailed in the rulemaking. The EPA proposal has defined the following four areas of focus which the states are to utilize to meet the proposed goals:

- increase efficiency of existing fossil-fuel plants;
- increase dispatch of existing natural gas combined-cycle units;
- utilize and expand the use of zero-emitting generation (additional renewables and nuclear); and
- increase demand-side energy efficiency.

Public hearings on the Clean Power Plan were held by the EPA on July 29 – August 1, 2014. We continue to follow developments related to the guidelines, including state regulatory developments. Due to the general nature of the guidelines and the lack of specifics regarding state implementation, we cannot predict whether the final rules relating to the guidelines will have a material impact on our results of operations or financial condition.

## *CSAPR*

The EPA proposed CSAPR, also known as the “Transport Rule,” that would require 27 states and the District of Columbia to significantly improve air quality by reducing power plant SO<sub>2</sub> and NO<sub>x</sub> emissions that contribute to ozone and fine particle pollution in other states. Emissions reductions were originally scheduled to take effect in 2012. However, on December 30, 2011, the D.C. Circuit issued a stay to the implementation of CSAPR pending judicial review. On August 21, 2012, the D.C. Circuit vacated CSAPR, ruling that the EPA had exceeded its statutory authority. On October 5, 2012, the EPA petitioned for a rehearing of the D.C. Circuit CSAPR decision. On January 24, 2013, the D.C. Circuit denied the EPA’s petition for rehearing. On June 24, 2013, the U.S. Supreme Court granted the United States’ petition asking the U.S. Supreme Court to review the D.C. Circuit decision on CSAPR and heard arguments on the matter in December 2013. On April 29, 2014, the U.S. Supreme Court overturned the D.C. Circuit’s 2012 ruling and reinstated CSAPR. On October 23, 2014, the D.C. Circuit formally reinstated CSAPR and scheduled to hear oral arguments on the remand for March 11, 2015. CAIR remains in effect through 2014 and we anticipate the EPA will implement CSAPR beginning January 1, 2015. We continue to follow developments related to CSAPR and we currently do not expect that this will have a material impact on our consolidated results of operations and financial condition.

**ITEM 6. EXHIBITS**

- 31.1 Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
- 31.2 Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
- 32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
- 32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350
- 101.INS XBRL Instance Document
- 101.SCH XBRL Taxonomy Extension Schema Document
- 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document
- 101.LAB XBRL Taxonomy Extension Label Linkbase Document
- 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document

SIGNATURE

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.

OLD DOMINION ELECTRIC COOPERATIVE  
Registrant

Date: November 12, 2014

\_\_\_\_\_  
/s/ Robert L. Kees  
Robert L. Kees  
Senior Vice President and Chief Financial Officer  
(Principal financial officer)

## EXHIBIT INDEX

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
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**CERTIFICATIONS**

I, Jackson E. Reasor, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
  - (a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
  - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and
  - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
  - (a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 12, 2014

/s/ JACKSON E. REASOR  
Jackson E. Reasor  
President and Chief Executive Officer  
(Principal executive officer)

**CERTIFICATIONS**

I, Robert L. Kees, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
  - (a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
  - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and
  - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
  - (a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 12, 2014

/s/ ROBERT L. KEES  
Robert L. Kees  
Senior Vice President and Chief Financial Officer  
(Principal financial officer)

**OLD DOMINION ELECTRIC COOPERATIVE**

**CERTIFICATION PURSUANT TO  
18 U.S.C. SECTION 1350,  
AS ADOPTED PURSUANT TO  
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-Q for the period ending September 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 12, 2014

\_\_\_\_\_  
/s/JACKSON E. REASOR

Jackson E. Reasor  
President and Chief Executive Officer  
(Principal executive officer)



**OLD DOMINION ELECTRIC COOPERATIVE**

**CERTIFICATION PURSUANT TO  
18 U.S.C. SECTION 1350,  
AS ADOPTED PURSUANT TO  
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-Q for the period ending September 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 12, 2014

\_\_\_\_\_  
/s/ROBERT L. KEES

Robert L. Kees  
Senior Vice President and Chief Financial Officer  
(Principal financial officer)