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, 2017

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	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

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

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
ACES	Alliance for Cooperative Energy Services Power Marketing, LLC
Alstom	Alstom Power, Inc.
Bear Island	Bear Island Paper WB LLC
Clover	Clover Power Station
EPC	Engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
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
North Anna Unit 3	A potential additional nuclear-powered generating unit at North Anna
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
REC	Rappahannock Electric Cooperative
RTO	Regional transmission organization
TEC	TEC Trading, Inc.
Virginia Power	Virginia Electric and Power Company
VSCC	Virginia State Corporation Commission
Wildcat Point	Wildcat Point Generation Facility
WOPC	White Oak Power Constructors
XBRL	Extensible Business Reporting Language

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PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2017	December 31, 2016
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 1,753,118	$ 1,746,852
Less accumulated depreciation	(885,118)	(855,068)
Net Property, plant, and equipment	868,000	891,784
Nuclear fuel, at amortized cost	12,656	22,138
Construction work in progress	814,570	736,996
Net Electric Plant	1,695,226	1,650,918
Investments:		
Nuclear decommissioning trust	176,487	159,155
Lease deposits	106,042	104,514
Unrestricted investments and other	7,097	6,599
Total Investments	289,626	270,268
Current Assets:		
Cash and cash equivalents	40,160	2,946
Accounts receivable	13,881	6,563
Accounts receivable–members	68,886	85,116
Fuel, materials, and supplies	55,357	56,353
Prepayments and other	3,893	4,737
Total Current Assets	182,177	155,715
Deferred Charges:		
Regulatory assets	44,647	49,682
Other	2,908	3,533
Total Deferred Charges	47,555	53,215
Total Assets	$ 2,214,584	$ 2,130,116
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 412,130	$ 402,857
Non-controlling interest	5,737	5,725
Total Patronage capital and Non-controlling interest	417,867	408,582
Long-term debt	1,239,050	990,083
Revolving credit facility	—	152,000
Total long-term debt and revolving credit facility	1,239,050	1,142,083
Total Capitalization	1,656,917	1,550,665
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	94,049	131,581
Accounts payable–members	76,908	66,380
Accrued expenses	24,519	5,806
Deferred energy	11,378	40,029
Total Current Liabilities	235,146	272,088
Deferred Credits and Other Liabilities:		
Asset retirement obligations	123,472	120,083
Obligations under long-term lease	101,994	96,930
Regulatory liabilities	96,491	89,020
Other	564	1,330
Total Deferred Credits and Other Liabilities	322,521	307,363
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,214,584	$ 2,130,116

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)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
	(in thousands)		(in thousands)	
Operating Revenues	$ 193,425	$ 222,802	$540,111	$678,410
Operating Expenses:				
Fuel	32,309	47,337	70,490	111,925
Purchased power	90,185	86,320	293,030	306,601
Transmission	24,280	30,008	72,001	92,368
Deferred energy	(2,408)	10,562	(28,651)	20,976
Operations and maintenance	12,753	13,100	37,325	38,277
Administrative and general	10,769	10,843	33,208	31,638
Depreciation and amortization	11,357	11,686	34,040	34,854
Amortization of regulatory asset/liability, net	1,021	608	1,001	685
Accretion of asset retirement obligations	1,257	1,212	3,769	3,633
Taxes, other than income taxes	2,089	2,104	6,280	6,323
Total Operating Expenses	183,612	213,780	522,493	647,280
Operating Margin	9,813	9,022	17,618	31,130
Other expense, net	(934)	(887)	(2,838)	(2,836)
Investment income	1,731	1,712	10,000	3,177
Interest income on North Anna Unit 3 cost recovery	85	—	4,512	—
Interest charges, net	(7,434)	(6,856)	(20,005)	(22,562)
Income taxes	(1)	—	(3)	(3)
Net Margin including Non-controlling interest	3,260	2,991	9,284	8,906
Non-controlling interest	(2)	—	(11)	(7)
Net Margin attributable to ODEC	3,258	2,991	9,273	8,899
Patronage Capital - Beginning of Period	408,872	396,884	402,857	390,976
Patronage Capital - End of Period	$ 412,130	$ 399,875	$412,130	$399,875

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

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	$ 9,284	$ 8,906
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	34,040	34,854
Other non-cash charges	14,153	13,739
Amortization of lease obligations	5,064	4,730
Interest on lease deposits	(2,274)	(2,229)
Change in current assets	10,752	9,712
Change in deferred energy	(28,651)	20,976
Change in current liabilities	23,457	(19,774)
Change in regulatory assets and liabilities	4,973	8,796
Change in deferred charges-other and deferred credits and other liabilities-other	262	1,406
Net Cash Provided by Operating Activities	71,060	81,116
Investing Activities:		
Purchases of held to maturity securities	(2,763)	—
Proceeds from sale of held to maturity securities	3,064	—
Increase in other investments	(9,822)	(2,152)
Electric plant additions	(120,939)	(217,033)
Net Cash Used for Investing Activities	(130,460)	(219,185)
Financing Activities:		
Issuance of long-term debt	250,000	—
Debt issuance costs	(1,386)	—
Draws on revolving credit facility	312,500	177,850
Repayments on revolving credit facility	(464,500)	(97,600)
Net Cash Provided by Financing Activities	96,614	80,250
Net Change in Cash and Cash Equivalents	37,214	(57,819)
Cash and Cash Equivalents - Beginning of Period	2,946	58,383
Cash and Cash Equivalents - End of Period	$ 40,160	$ 564

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

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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, 2017, our consolidated results of operations for the three and nine months ended September 30, 2017 and 2016, and cash flows for the nine months ended September 30, 2017 and 2016. The consolidated results of operations for the three and nine months ended September 30, 2017, 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 2016 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 as of September 30, 2017 and December 31, 2016. 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 condensed 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, 2017 and December 31, 2016:

	September 30, 2017	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in thousands)		
Nuclear decommissioning trust [(1)]	$ 59,360	$ 59,360	$ —	$ —
Nuclear decommissioning trust - net asset value [(1)(2)]	117,127	—	—	—
Unrestricted investments and other [(3)]	293	—	293	—
Derivatives - gas and power [(4)]	1,088	435	653	—
Total Financial Assets	$ 177,868	$ 59,795	$ 946	$ —

	December 31, 2016	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in thousands)		
Nuclear decommissioning trust [(1)]	$ 48,142	$ 48,142	$ —	$ —
Nuclear decommissioning trust - net asset value [(1)(2)]	111,013	—	—	—
Unrestricted investments and other [(3)]	247	—	247	—
Derivatives - gas and power [(4)]	6,968	4,874	2,094	—
Total Financial Assets	$ 166,370	$ 53,016	$ 2,341	$ —

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

(2) Nuclear decommissioning trust includes investments measured at net asset value per share (or its equivalent) as a practical expedient and these investments have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Condensed Consolidated Balance Sheet.

(3) Unrestricted investments and other includes investments that are related to equity securities.

(4) Derivatives - gas and power represent natural gas futures contracts. Level 1 are indexed against NYMEX. Level 2 are valued by ACES using observable market inputs for similar transactions. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2016 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 2016 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:

		Quantity	
Commodity	**Unit of Measure**	**As of September 30, 2017**	**As of December 31, 2016**
Natural Gas	MMBTU	18,020,000	14,250,000

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

		Fair Value	
	Balance Sheet Location	**As of September 30, 2017**	**As of December 31, 2016**
		(in thousands)	
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges-other	$ 1,088	$ 6,968
Total derivatives in an asset position		$ 1,088	$ 6,968

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, 2017 and 2016

Derivatives Accounted for Utilizing Regulatory Accounting	**Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of September 30,**		**Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income**	**Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Three Months Ended September 30,**		**Nine Months Ended September 30,**	
	2017	**2016**		**2017**	**2016**	**2017**	**2016**
	(in thousands)			(in thousands)		(in thousands)	
Natural gas futures contracts	$ 1,123	$ 704	Fuel	$ (129)	$ 77	$ 870	$ (2,421)
Total	$ 1,123	$ 704		$ (129)	$ 77	$ 870	$ (2,421)

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 a default 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 as of September 30, 2017 and December 31, 2016:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
				(in thousands)		
September 30, 2017						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 54,009	$ 4,982	$ —	$ 58,991	$ 58,991
Equity securities	Available for sale	75,359	41,768	—	117,127	117,127
Cash and other	Available for sale	369	—	—	369	369
Total Nuclear Decommissioning Trust		$ 129,737	$ 46,750	$ —	$ 176,487	$ 176,487
Lease Deposits [2]						
Government obligations	Held to maturity	$ 106,042	$ 1,369	$ —	$ 107,411	$ 106,042
Total Lease Deposits		$ 106,042	$ 1,369	$ —	$ 107,411	$ 106,042
Unrestricted investments						
Government obligations	Held to maturity	$ 2,342	$ —	$ (7)	$ 2,335	$ 2,342
Debt securities	Held to maturity	2,342	—	—	2,342	2,342
Total Unrestricted Investments		$ 4,684	$ —	$ (7)	$ 4,677	$ 4,684
Other						
Equity securities	Trading	$ 214	$ 79	$ —	$ 293	$ 293
Non-marketable equity investments	Equity	2,120	2,113	—	4,233	2,120
Total Other		$ 2,334	$ 2,192	$ —	$ 4,526	$ 2,413
						$ 289,626
December 31, 2016						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 44,086	$ 3,537	$ —	$ 47,623	$ 47,623
Equity securities	Available for sale	75,332	35,958	(277)	111,013	111,013
Cash and other	Available for sale	519	—	—	519	519
Total Nuclear Decommissioning Trust		$ 119,937	$ 39,495	$ (277)	$ 159,155	$ 159,155
Lease Deposits [2]						
Government obligations	Held to maturity	$ 104,514	$ 2,948	$ —	$ 107,462	$ 104,514
Total Lease Deposits		$ 104,514	$ 2,948	$ —	$ 107,462	$ 104,514
Unrestricted investments						
Government obligations	Held to maturity	$ 2,000	$ 1	$ —	$ 2,001	$ 2,000
Debt securities	Held to maturity	2,210	6	—	2,216	2,210
Total Unrestricted Investments		$ 4,210	$ 7	$ —	$ 4,217	$ 4,210
Other						
Equity securities	Trading	$ 198	$ 49	$ —	$ 247	$ 247
Non-marketable equity investments	Equity	2,142	2,012	—	4,154	2,142
Total Other		$ 2,340	$ 2,061	$ —	$ 4,401	$ 2,389
						$ 270,268

(1) 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 2016 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, respectively.

(2) 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 2016 Annual Report on Form 10-K.

Our investments by classification as of September 30, 2017 and December 31, 2016, were as follows:

Description	September 30, 2017 Cost	September 30, 2017 Carrying Value	December 31, 2016 Cost	December 31, 2016 Carrying Value
	(in thousands)		(in thousands)	
Available for sale	$ 129,737	$ 176,487	$ 119,937	$ 159,155
Held to maturity	110,726	110,726	108,724	108,724
Equity	2,120	2,120	2,142	2,142
Trading	214	293	198	247
Total	$ 242,797	$ 289,626	$ 231,001	$ 270,268

Contractual maturities of debt securities as of September 30, 2017, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Available for sale [(1)]	$ —	$ —	$ 58,991	$ —	$ 58,991
Held to maturity	75,595	35,131	—	—	110,726
Total	$ 75,595	$ 35,131	$ 58,991	$ —	$ 169,717

(1) 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*

Wildcat Point Generation Facility

We are currently constructing, and will be the sole owner of, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. While the facility was scheduled to become operational in mid-2017, based upon the most recent information available, we believe that Wildcat Point will achieve substantial completion in the fourth quarter of 2017. WOPC, the EPC contractor, claims that the delay is associated with the incurrence of additional work and other matters, including alleged misrepresentation under the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. On May 24, 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. An amended complaint was filed on July 21, 2017. On August 21, 2017, motions were filed by Alstom and us to transfer venue from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia, and on November 7, 2017, these motions were granted. We believe that this complaint is without merit, plan to vigorously defend against WOPC's claims against us, and do not believe any liability is estimable at this time. Further, we disagree that we have additional liability under the contract and therefore have not revised our estimated project cost of $834.3 million, before consideration of any liquidated damages as a result of the project delay. We do not believe that any such delay in the substantial completion of the Wildcat Point facility, or any additional amounts associated with the delay, including PJM capacity delay charges, for which we may be ultimately responsible, are reasonably likely to have a material adverse effect on our results of operations or financial condition due to our ability to collect such amounts through rates charged to our member distribution cooperatives. Even if we are ultimately responsible for additional costs, any such amounts may be offset in part by liquidated damages under the contract associated with WOPC’s delay in achieving substantial completion.

Additionally, on September 29, 2017, we filed a complaint in the United States District Court for the Eastern District of Virginia against WOPC, a joint venture, and its constituent members, PCL Industrial Construction Company and Sargent & Lundy, L.L.C., alleging that the companies have breached the contract they entered into with ODEC to engineer, procure, and construct Wildcat Point. See “Item 1 – Legal Proceedings.”

Through September 30, 2017, we capitalized construction costs related to Wildcat Point totaling $780.1 million, including $68.6 million of capitalized interest, offset by $39.0 million of liquidated damages.

FERC Proceeding Related to Formula Rate

On September 30, 2013, we filed with FERC to revise our cost-based formula rate in order 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. On April 13, 2015, we received an initial decision from the hearing judge. On January 19, 2017, FERC issued its order on the hearing judge's initial decision. On February 21, 2017, we submitted our compliance filing, revising the formula rate as directed in the order. Additionally, on February 21, 2017, Bear Island filed a request for rehearing. On March 22, 2017, FERC issued an order granting rehearing of its initial order for the limited purpose of FERC's further consideration of the matter. Our formula rate remains in effect subject to refund pending a final order from FERC. If a refund is ultimately determined, we believe it will result in a reallocation of costs among our member distribution cooperatives.

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. On June 9, 2015, FERC denied our petition, on July 9, 2015, we filed a request for rehearing, and on August 10, 2015, FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. On March 1, 2016, FERC denied our request for rehearing, on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit, and on October 24, 2017, the court heard oral arguments. Also related to this matter, on January 5, 2017, we filed a complaint and request for relief in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. We have not recorded a receivable related to this matter.

Long-term Debt

On July 6, 2017, we issued $250.0 million of long-term debt in a private placement transaction. The issuance consists of $250.0 million of 3.33% First Mortgage Bonds, 2017 Series A due December 1, 2037.

Revolving Credit Facility

We maintain a $500.0 million revolving credit facility to cover our short-term and medium-term funding needs that are not met by cash from operations or other available funds. The syndicated credit agreement associated with the facility was amended and restated on March 3, 2017, and commitments under this agreement extend until March 3, 2022. As of September 30, 2017, we had outstanding under this facility no borrowings and $12.2 million in letters of credit. As of December 31, 2016, we had outstanding under this facility $152.0 million in borrowings and $5.2 million in letters of credit.

Limited Exception under Wholesale Power Contracts

We have a wholesale power contract with each of our member distribution cooperatives. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions. One of the limited exceptions permits each of our member distribution cooperatives, with 180 days prior written notice, to receive up to the greater of 5% of its demand and associated energy or 5 MW and associated energy from owned generation or other suppliers. If all of our member distribution cooperatives elected to utilize the 5% or 5 MW exception, we estimate the current impact would be a reduction of approximately 175 MW of demand and associated energy. The following table summarizes the cumulative removal of load requirements under this exception since January 1, 2016.

Date	**MW**
January 1, 2016	9
May 1, 2016	60
June 1, 2017	65
May 1, 2018	106

We do not anticipate that the utilization of this exception by our member distribution cooperatives will have a material impact on our financial condition, results of operations, or cash flows.

Retail Choice in Virginia

In Virginia, retail choice in the selection of a power supplier is available to customers that consume at least 5 MW of power individually or in the aggregate (with aggregation subject to the approval of the VSCC) and that do not account for more than 1% of the incumbent utility's peak load during the past year. Currently, no customer of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Beginning June 1, 2016, Bear Island, an industrial customer of REC and the only customer of any of our member distribution cooperatives that has noncoincident peak demand that exceeds 90 MW, elected to purchase its power requirements from an alternate supplier. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows.

North Anna Unit 3

In 2011, we decided not to participate in North Anna Unit 3, finalized our withdrawal as a participant in the project and transferred our interest to Virginia Power. In 2011, we established a regulatory asset of $22.7 million for our early stage development costs incurred for North Anna Unit 3. In 2015, we recovered 70% of these costs from Virginia Power and, with our board of directors' approval, amortized the remaining balance in 2015. On June 1, 2017, Virginia Power agreed to return the remaining balance of North Anna Unit 3 development costs that we incurred as part of the resolution of other regulatory matters with Virginia Power. The remaining balance of North Anna Unit 3 development costs, including interest through May 2018, totals $11.6 million. In the second quarter of 2017, we recorded $6.9 million as amortization of regulatory asset/liability, net, and $4.4 million as interest income on North Anna Unit 3 cost recovery on our Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital. During the second quarter of 2017, we received a payment of $6.8 million and established a receivable for the remaining balance, which will continue to accrue interest. Virginia Power agreed to pay the remaining balance in the second quarter of 2018.

New Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09 Revenue from Contracts with Customers. This update requires entities to recognize revenue when the transfer of promised goods or services to customers occurs in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. We supply power requirements (energy and demand) to our eleven member distribution cooperatives subject to substantially identical wholesale power contracts with each of them. The revenues from these wholesale power contracts constituted at least 95% of our total revenues for the past three years. We are in the process of evaluating our wholesale power and other contracts. We have not identified any material impact to our recognition of revenue from the sale of power to our member distribution cooperatives, but are still completing our review of the wholesale power contracts as well as other contracts. We plan to adopt this standard for the fiscal year beginning January 1, 2018.

In February 2016, the FASB issued Accounting Standards Update 2016-02 Leases (Subtopic 835-30). This update revised accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. The update requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. We are currently evaluating the impact of this pronouncement. We plan to adopt this standard for the fiscal year beginning January 1, 2019.

Subsequent Event

On November 7, 2017, our board of directors approved an additional equity contribution of $14.1 million and declared a patronage capital retirement of $14.1 million, to be paid on April 2, 2018. Also, on November 7, 2017, our board of directors approved the establishment of a $15.0 million regulatory liability, to be amortized over a 24-month period, beginning January 1, 2018, which will reduce revenue requirements in 2018 and 2019.

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, 2017, there have been no significant changes in our critical accounting policies as disclosed in our 2016 Annual Report on Form 10-K. These policies include the accounting for regulated operations, 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 three and nine months ended September 30, 2017, were primarily impacted by decreases in our total energy rate, changes in our member distribution cooperatives' requirements for power, and the dispatch of our generating facilities, and for the nine months ended September 30, 2017, our continued investment in Wildcat Point and the return of North Anna Unit 3 development costs.

- In 2016 and 2017, we implemented decreases to our total energy rate that contributed to the 11.8% and 15.1% decrease in the average cost of energy we charged to our member distribution cooperatives, for the three and nine months ended September 30, 2017, respectively. These decreases to our total energy rate also contributed to the $28.7 million decrease in our over-collected deferred energy balance.
- Our energy sales in MWh to our member distribution cooperatives were 7.7% and 7.9% lower for the three and nine months ended September 30, 2017, respectively. We had decreases in our load requirements related to retail choice in Virginia and a limited exception provision in our wholesale power contract. Additionally, we experienced milder weather during 2017.

- Clover generation decreased 31.6% and 39.6% for the three and nine months ended September 30, 2017, respectively, due to PJM’s economic dispatch of the facility and reduced operational availability. Our combustion turbine facilities generation decreased 48.5% and 43.3% for the three and nine months ended September 30, 2017, respectively, due to PJM’s economic dispatch of the facilities. These factors contributed to the $15.0 million, or 31.7%, decrease in fuel expense for the three months ended September 30, 2017, and the $41.4 million, or 37.0%, decrease for the nine months ended September 30, 2017.
- During the nine months ended September 30, 2017, we capitalized $64.2 million, of construction costs related to Wildcat Point.
- On June 1, 2017, Virginia Power agreed to return the remaining balance of North Anna Unit 3 development costs that we incurred prior to our 2011 decision not to participate in North Anna Unit 3. In the second quarter of 2017, we recorded $11.3 million, comprised of $6.9 million of amortization of regulatory asset/liability, net, and $4.4 million of interest income on North Anna Unit 3 cost recovery. During the second quarter of 2017, we received a payment of $6.8 million and established a receivable for the remaining balance.

Wildcat Point Generation Facility

We are currently constructing, and will be the sole owner of, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. While the facility was scheduled to become operational in mid-2017, based upon the most recent information available, we believe that Wildcat Point will achieve substantial completion in the fourth quarter of 2017. WOPC, the EPC contractor, claims that the delay is associated with the incurrence of additional work and other matters, including alleged misrepresentation under the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. On May 24, 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. An amended complaint was filed on July 21, 2017. On August 21, 2017, motions were filed by Alstom and us to transfer venue from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia, and on November 7, 2017, these motions were granted. We believe that this complaint is without merit, plan to vigorously defend against WOPC's claims against us, and do not believe any liability is estimable at this time. Further, we disagree that we have additional liability under the contract and therefore have not revised our estimated project cost of $834.3 million, before consideration of any liquidated damages as a result of the project delay. We do not believe that any such delay in the substantial completion of the Wildcat Point facility, or any additional amounts associated with the delay, including PJM capacity delay charges, for which we may be ultimately responsible, are reasonably likely to have a material adverse effect on our results of operations or financial condition due to our ability to collect such amounts through rates charged to our member distribution cooperatives. Even if we are ultimately responsible for additional costs, any such amounts may be offset in part by liquidated damages under the contract associated with WOPC’s delay in achieving substantial completion.

Additionally, on September 29, 2017, we filed a complaint in the United States District Court for the Eastern District of Virginia against WOPC, a joint venture, and its constituent members, PCL Industrial Construction Company and Sargent & Lundy, L.L.C., alleging that the companies have breached the contract they entered into with ODEC to engineer, procure, and construct Wildcat Point. See “Item 1 – Legal Proceedings.”

Through September 30, 2017, we capitalized construction costs related to Wildcat Point totaling $780.1 million, including $68.6 million of capitalized interest, offset by $39.0 million of liquidated damages.

Limited Exception under Wholesale Power Contracts

We have a wholesale power contract with each of our member distribution cooperatives. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions. One of the limited exceptions permits each of our member distribution cooperatives, with 180 days prior written notice, to receive up to the greater of 5% of its demand and associated energy or 5 MW and associated energy from owned generation or other suppliers. If all of our member distribution cooperatives elected to utilize the 5% or 5 MW exception, we estimate the current impact would be a reduction of approximately 175 MW of demand and associated energy. The following table summarizes the cumulative removal of load requirements under this exception since January 1, 2016.

Date	MW
January 1, 2016	9
May 1, 2016	60
June 1, 2017	65
May 1, 2018	106

We do not anticipate that the utilization of this exception by our member distribution cooperatives will have a material impact on our financial condition, results of operations, or cash flows. For further discussion on Wholesale Power Contracts, see "Business—Members—Member Distribution Cooperatives—Wholesale Power Contracts" in Item 1 of our 2016 Annual Report on Form 10-K.

Retail Choice in Virginia

In Virginia, retail choice in the selection of a power supplier is available to customers that consume at least 5 MW of power individually or in the aggregate (with aggregation subject to the approval of the VSCC) and that do not account for more than 1% of the incumbent utility's peak load during the past year. Currently, no customer of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Beginning June 1, 2016, Bear Island, an industrial customer of REC and the only customer of any of our member distribution cooperatives that has noncoincident peak demand that exceeds 90 MW, elected to purchase its power requirements from an alternate supplier. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows. For further discussion on Retail Choice in Virginia, see "Business—Members—Member Distribution Cooperatives—Competition" in Item 1 of our 2016 Annual Report on Form 10-K.

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. The base energy rate is 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 base energy rate is reset in accordance with our budget and the energy adjustment rate is reset to 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 "Legal Proceedings" in Part II, Item 1.

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. We 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 that PJM allocates to ODEC and all other PJM 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.

- 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 recorded.
- 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.

We may revise our budget at any time to the extent that our current budget does not accurately reflect our costs and expenses or estimates of our sales of power. Increases or decreases in our budget automatically amend the energy and/or the demand components of our formula rate, as necessary. The formula rate also permits us to adjust revenues from the member distribution cooperatives to equal our actual total demand costs. We make these adjustments utilizing Margin Stabilization. If at any time our board of directors determines that the formula does not meet all of our costs and expenses, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval.

The following table details the Margin Stabilization adjustments for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Margin Stabilization adjustment	$12,871	$11,491	$49,892	$13,713

For further discussion of Margin Stabilization, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Margin Stabilization” in Item 7 of our 2016 Annual Report on Form 10-K.

On November 7, 2017, our board of directors approved an additional equity contribution of $14.1 million and declared a patronage capital retirement of $14.1 million, to be paid on April 2, 2018. Also, on November 7, 2017, our board of directors approved the establishment of a $15.0 million regulatory liability, to be amortized over a 24-month period, beginning January 1, 2018, which will reduce revenue requirements in 2018 and 2019.

Weather

Weather affects the demand for electricity. Relatively higher or lower temperatures tend to increase the demand for energy to use air conditioning and heating systems, respectively. Mild weather generally reduces the demand because heating and air conditioning systems are operated less. Weather also plays a role in the price of market energy through its effects on the market price for fuel, particularly natural gas. Heating and cooling degree days are measurement tools used to quantify the need to utilize heating or cooling, respectively, for a building. The heating and cooling degree days for the three and nine months ended September 30, 2017, were as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Heating degree days	—	—	—	1,637	2,087	(21.6)%
Cooling degree days	897	1,255	(28.5)%	1,182	1,519	(22.2)%

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; diesel-fired 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, 2017 and 2016, were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017		2016		2017		2016	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	543,468	17.0%	794,095	23.2%	1,302,298	14.6%	2,154,822	22.0%
North Anna	431,770	13.5	418,197	12.2	1,408,412	15.9	1,313,814	13.4
Louisa	79,779	2.5	157,798	4.6	169,908	1.9	310,577	3.2
Marsh Run	221,867	7.0	307,072	9.0	309,053	3.5	438,925	4.5
Rock Springs	97,285	3.1	310,100	9.0	143,571	1.6	347,670	3.5
Distributed Generation	350	—	960	—	538	—	1,063	—
Total Generated	1,374,519	43.1	1,988,222	58.0	3,333,780	37.5	4,566,871	46.6
Purchased:								
Other than renewable:								
Long-term and short-term	1,354,004	42.4	1,008,487	29.4	3,966,274	44.7	4,008,255	40.9
Spot market	357,639	11.2	312,505	9.1	1,043,338	11.7	696,951	7.1
Total Other than renewable	1,711,643	53.6	1,320,992	38.5	5,009,612	56.4	4,705,206	48.0
Renewable [(1)]	105,533	3.3	120,356	3.5	537,604	6.1	530,260	5.4
Total Purchased	1,817,176	56.9	1,441,348	42.0	5,547,216	62.5	5,235,466	53.4
Total Available Energy	3,191,695	100.0%	3,429,570	100.0%	8,880,996	100.0%	9,802,337	100.0%

(1) 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 generating facilities, which are under dispatch control of PJM. Typically, nuclear facilities are almost always dispatched and coal-fired and combustion turbine facilities are generally dispatched based upon economic factors, including the market price of energy, and to meet system reliability requirements. For further discussion on PJM, see "Business—Power Supply Resources—PJM" in Item 1 of our 2016 Annual Report on Form 10-K.

Operational Availability

The operational availability of our owned generating resources for the three and nine months ended September 30, 2017 and 2016, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Clover	90.0%	98.0%	77.9%	88.9%
North Anna	88.6	86.8	95.9	89.1
Louisa	87.7	99.6	92.8	98.9
Marsh Run	99.7	100.0	99.6	97.7
Rock Springs	100.0	93.7	96.6	93.3

Capacity Factor

The output of Clover and North Anna, our baseload facilities, for the three and nine months ended September 30, 2017 and 2016, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Clover	57.5%	83.0%	46.7%	75.8%
North Anna	89.1	86.3	98.0	90.2

Due to outages and economic dispatch by PJM, both units at Clover experienced reduced dispatch during the first nine months of 2017.

Outages

The scheduled and unscheduled outages for Clover and North Anna for the three and nine months ended September 30, 2017 and 2016, were as follows:

	Clover				North Anna			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016	2017	2016	2017	2016
	(in days)		(in days)		(in days)		(in days)	
Scheduled	—	—	77.5	35.1	21.0	20.0	21.0	55.3
Unscheduled	18.3	3.6	43.0	25.5	—	4.3	1.4	4.3
Total	18.3	3.6	120.5	60.6	21.0	24.3	22.4	59.6

The outage days above for Clover and North Anna reflect the total number of outage days for the two units at Clover and the two units at North Anna.

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 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 under its rates for providing energy imbalance service. 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 and energy sales in MWh by type of purchaser for the three and nine months ended September 30, 2017 and 2016, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Revenues from sales to:	(in thousands)		(in thousands)	
Member distribution cooperatives				
Energy revenues [1]	$ 108,462	$ 133,201	$ 305,735	$ 390,910
Demand revenues [2]	75,416	81,764	216,690	262,963
Total revenues from sales to member distribution cooperatives	183,878	214,965	522,425	653,873
Non-members [3]	9,547	7,837	17,686	24,537
Total operating revenues	$ 193,425	$ 222,802	$ 540,111	$ 678,410
Energy sales to:	(in MWh)		(in MWh)	
Member distribution cooperatives	3,003,796	3,254,047	8,466,871	9,194,937
Non-members	173,018	147,590	385,295	526,815
Total energy sales	3,176,814	3,401,637	8,852,166	9,721,752
	(per MWh)		(per MWh)	
Average cost of energy to member distribution cooperatives	$ 36.11	$ 40.93	$ 36.11	$ 42.51
Average cost of demand to member distribution cooperatives	25.11	25.13	25.59	28.60
Average total cost to member distribution cooperatives	$ 61.22	$ 66.06	$ 61.70	$ 71.11

(1) Includes sales of renewable energy credits of $2 thousand and $18 thousand for the three and nine months ended September 30, 2017, respectively, and $0.9 million and $2.5 million for the three and nine months ended September 30, 2016, respectively.

(2) Includes margin stabilization adjustment of $12.9 million and $49.9 million for the three and nine months ended September 30, 2017, respectively, and $11.5 million and $13.7 million for the three and nine months ended September 30, 2016, respectively. The impact of the margin stabilization adjustment for all periods presented is a reduction to demand revenues. See “Factors Affecting Results—Formula Rate” above.

(3) Includes sales of renewable energy credits of $2.2 million and $3.7 million for the three and nine months ended September 30, 2017, respectively, and $1.7 million and $8.4 million for the three and nine months ended September 30, 2016, respectively

Member Distribution Cooperatives

For the three and nine months ended September 30, 2017, total revenues from sales to our member distribution cooperatives were 14.5% and 20.1% lower, respectively, as compared to the same periods in 2016, due to the decrease in energy and demand revenues. Energy revenues decreased $24.7 million, or 18.6%, and $85.2 million, or 21.8%, respectively, for the three and nine months ended September 30, 2017, as compared to the same periods in 2016 due to the decrease in the average cost of energy sold to our member distribution cooperatives and the decrease in energy sales in MWh to our member distribution cooperatives. The average cost of energy sold to our member distribution cooperatives decreased 11.8% and 15.1%, respectively, and the energy sales in MWh to our member distribution cooperatives decreased 7.7% and 7.9%, respectively. The average cost of energy sold to our member distribution cooperatives was impacted by the rate decreases we implemented in 2016 and 2017 (see table below). The decrease in the volume of energy sales for the nine months ended September 30, 2017, was substantially a result of the reduction in our load requirements related to retail choice in Virginia and a limited exception provision in our wholesale power contract. See "Retail Choice in Virginia" and "Limited Exception under Wholesale Power Contracts" above. These two events resulted in a load reduction of 411,750 MWh for the nine months ended September 30, 2017, as compared to the same period in 2016. Additionally, we experienced milder weather in 2017. Demand revenues decreased $6.3 million, or 7.8%, and $46.3 million, or 17.6%, respectively, for the three and nine months ended September 30, 2017, as compared to the same periods in 2016 primarily due to decreases in transmission expense and capacity-related purchased power expense, and for the nine months ended September 30, 2017, the recovery of North Anna Unit 3 development costs.

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:

Effective Date of Rate Change	% Change
January 1, 2016	(5.4)
April 1, 2016	(6.8)
September 1, 2016	(6.5)
January 1, 2017	(6.7)

Non-members

Revenues from sales to non-members for the three months ended September 30, 2017, increased $1.7 million, or 21.8%, as compared to the same period in 2016. Revenues from sales to non-members for the nine months ended September 30, 2017, decreased $6.9 million, or 27.9%, as compared to the same period in 2016, due to a $4.7 million decrease in revenue from sales of renewable energy credits and a $2.2 million decrease in revenue from sales of excess energy. The decrease in revenue from sales of excess energy for the nine months ended September 30, 2017, was primarily due to a 26.9% decrease in volume of excess energy sales. 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.

Operating Expenses

The following is a summary of the components of our operating expenses for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Fuel	$ 32,309	$ 47,337	$ 70,490	$111,925
Purchased power	90,185	86,320	293,030	306,601
Transmission	24,280	30,008	72,001	92,368
Deferred energy	(2,408)	10,562	(28,651)	20,976
Operations and maintenance	12,753	13,100	37,325	38,277
Administrative and general	10,769	10,843	33,208	31,638
Depreciation and amortization	11,357	11,686	34,040	34,854
Amortization of regulatory asset/liability, net	1,021	608	1,001	685
Accretion of asset retirement obligations	1,257	1,212	3,769	3,633
Taxes, other than income taxes	2,089	2,104	6,280	6,323
Total Operating Expenses	$183,612	$213,780	$522,493	$647,280

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 transmission expense, the capacity portion of our purchased power expense, the fixed portion of operations and maintenance expense, administrative and general expense, and depreciation and amortization 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 decreased $30.2 million, or 14.1%, and $124.8 million, or 19.3%, for the three and nine months ended September 30, 2017, respectively, as compared to the same periods in 2016. The decrease for the three and nine months ended September 30, 2017, was primarily due to decreases in deferred energy expense, fuel expense, and transmission expense.

- Deferred energy expense decreased $13.0 million and $49.6 million for the three and nine months ended September 30, 2017, respectively, as compared to the same periods in 2016. For the three and nine months ended September 30, 2017, we under-collected $2.4 million and $28.7 million, respectively. For the three and nine months ended September 30, 2016, we over-collected $10.6 million and $21.0 million, respectively. Deferred energy expense represents the difference between energy revenues and energy expenses. 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 2016 Annual Report on Form 10-K.
- Fuel expense decreased $15.0 million, or 31.7%, and $41.4 million, or 37.0%, for the three and nine months ended September 30, 2017, respectively, as compared to the same periods in 2016. Clover generation decreased 31.6% and 39.6% for the three and nine months ended September 30, 2017, respectively, due to reduced operational availability as a result of additional outage days and PJM's economic dispatch of the facility. Our combustion turbine facilities generation decreased 48.5% and 43.3% for the three and nine months ended September 30, 2017, respectively, due to PJM's economic dispatch of the facilities.
- Transmission expense decreased $5.7 million, or 19.1%, and $20.4 million, or 22.0%, for the three and nine months ended September 30, 2017, as compared to the same periods in 2016, primarily due to decreases in PJM charges for network transmission services.

Other Items

Investment Income

Investment income was relatively flat for the three months ended September 30, 2017, and increased $6.8 million for the nine months ended September 30, 2017, as compared to the same periods in 2016, primarily due to increased earnings on our nuclear decommissioning trust.

Interest Income on North Anna Unit 3 Cost Recovery

In 2011, we decided not to participate in North Anna Unit 3, finalized our withdrawal as a participant in the project and transferred our interest to Virginia Power. In 2011, we established a regulatory asset of $22.7 million for our early stage development costs incurred for North Anna Unit 3. In 2015, we recovered 70% of these costs from Virginia Power and, with our board of directors' approval, amortized the remaining balance in 2015. On June 1, 2017, Virginia Power agreed to return the remaining balance of North Anna Unit 3 development costs that we incurred as part of the resolution of other regulatory matters with Virginia Power. The remaining balance of North Anna Unit 3 development costs, including interest through May 2018, totals $11.6 million. In the second quarter of 2017, we recorded $6.9 million as amortization of regulatory asset/liability, net, and $4.4 million as interest income on North Anna Unit 3 cost recovery on our Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital. During the second quarter of 2017, we received a payment of $6.8 million and established a receivable for the remaining balance, which will continue to accrue interest. Virginia Power agreed to pay the remaining balance in the second quarter of 2018.

Interest Charges, Net

The primary factors affecting our interest charges, net are issuance of indebtedness, scheduled payments of principal on our indebtedness, interest charges related to our revolving credit facility, and capitalized interest. The major components of interest charges, net for the three and nine months ended September 30, 2017 and 2016, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)		(in thousands)	
Interest on long-term debt	$ (15,781)	$ (14,199)	$ (43,353)	$ (42,596)
Interest on revolving credit facility	(324)	(534)	(2,404)	(1,062)
Other interest	(189)	(223)	(608)	(836)
Total interest charges	(16,294)	(14,956)	(46,365)	(44,494)
Allowance for borrowed funds used during construction	8,860	8,100	26,360	21,932
Interest charges, net	$ (7,434)	$ (6,856)	$ (20,005)	$ (22,562)

Interest charges, net was relatively flat for the three months ended September 30, 2017, and decreased $2.6 million, or 11.3%, for the nine months ended September 30, 2017, as compared to the same periods in 2016, substantially due to the increase in allowance for borrowed funds used during construction (capitalized interest) related to Wildcat Point.

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, was relatively flat for the three and nine months ended September 30, 2017, as compared to the same periods in 2016.

Financial Condition

The principal changes in our financial condition from December 31, 2016 to September 30, 2017, were caused by increases in long-term debt and construction work in progress, and decreases in revolving credit facility, accounts payable, and deferred energy.

- Long-term debt increased $249.0 million due to the issuance of long-term debt on July 6, 2017.
- Construction work in progress increased $77.6 million substantially due to expenditures related to Wildcat Point.
- Revolving credit facility decreased $152.0 million due the repayment of outstanding borrowings under this facility using proceeds from the July 2017 debt issuance.
- Accounts payable decreased $37.5 million primarily due to decreased payables for construction and purchased power.
- Deferred energy decreased $28.7 million as a result of the under-collection of our energy costs in 2017. The deferred energy balance was a liability of $11.4 million and $40.0 million as of September 30, 2017 and December 31, 2016, respectively.

Liquidity and Capital Resources

Sources

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

Operations

During the first nine months of 2017 and 2016, our operating activities provided cash flows of $71.1 million and $81.1 million, respectively. Operating activities in 2017 were primarily impacted by the following:

- Deferred energy changed $28.7 million due to the under-collection of our energy costs in 2017 as compared to the over-collection of energy costs in 2016;
- Current liabilities changed $23.5 million primarily due to the change in accrued expenses and accounts payable–members; and
- Current assets changed $10.8 million primarily due to the change in accounts receivable–members, partially offset by the change in accounts receivable.

Revolving Credit Facility

We maintain a $500.0 million revolving credit facility to cover our short-term and medium-term funding needs that are not met by cash from operations or other available funds. The syndicated credit agreement associated with the facility was amended and restated on March 3, 2017, and commitments under this agreement extend until March 3, 2022. As of September 30, 2017, we had outstanding under this facility no borrowings and $12.2 million in letters of credit. As of December 31, 2016, we had outstanding under this facility $152.0 million in borrowings and $5.2 million in letters of credit.

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.

On July 6, 2017, we issued $250.0 million of long-term debt in a private placement transaction. The issuance consists of $250.0 million of 3.33% First Mortgage Bonds, 2017 Series A due December 1, 2037.

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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the third quarter of 2017.

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. 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.

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 in order 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. On April 13, 2015, we received an initial decision from the hearing judge. On January 19, 2017, FERC issued its order on the hearing judge's initial decision. On February 21, 2017, we submitted our compliance filing, revising the formula rate as directed in the order. Additionally, on February 21, 2017, Bear Island filed a request for rehearing. On March 22, 2017, FERC issued an order granting rehearing of its initial order for the limited purpose of FERC's further consideration of the matter. Our formula rate remains in effect subject to refund pending a final order from FERC. If a refund is ultimately determined, we believe it will result in a reallocation of costs among our member distribution cooperatives.

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. On June 9, 2015, FERC denied our petition, on July 9, 2015, we filed a request for rehearing, and on August 10, 2015, FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. On March 1, 2016, FERC denied our request for rehearing, on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit, and on October 24, 2017, the court heard oral arguments. Also related to this matter, on January 5, 2017, we filed a complaint and request for relief in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. We have not recorded a receivable related to this matter.

Wildcat Point

Wildcat Point was scheduled to become operational in mid-2017; however, based upon the most recent information available, we believe that Wildcat Point will achieve substantial completion in the fourth quarter of 2017. WOPC, the EPC contractor, claims that the delay is associated with the incurrence of additional work and other matters, including alleged misrepresentation under the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. On May 24, 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. An amended complaint was filed on July 21, 2017. On August 21, 2017, motions were filed by Alstom and us to transfer venue from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia, and on November 7, 2017, these motions were granted. We have reviewed the asserted claims of WOPC and believe they are without merit. We do not believe any liability is estimable or probable and intend to vigorously defend against these claims.

Additionally, on September 29, 2017, we filed a complaint in the U.S. District Court for the Eastern District of Virginia against WOPC, a joint venture, and its constituent members, PCL Industrial Construction Company and Sargent & Lundy, L.L.C., alleging that the companies have breached the contract they entered into with ODEC to engineer, procure, and construct Wildcat Point.

If it is ultimately determined that we owe any such amounts to WOPC, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates to our member distribution cooperatives.

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 2016 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

Appointment of Interim CEO

On November 7, 2017, our board of directors approved the appointment of Mr. Robert L. Kees to serve as Interim President and Chief Executive Officer ("Interim CEO"), effective January 16, 2018, following Mr. Jackson E. Reasor's retirement on January 15, 2018. Mr. Kees will also continue to serve as Chief Financial Officer. The search for Mr. Reasor's permanent replacement is underway and Mr. Kees will serve as Interim CEO until the appointment of the permanent President and Chief Executive Officer ("CEO").

Amendment of Material Contract

Salaries for all of our employees other than the CEO are determined based on market data for positions with similar responsibilities. Our board of directors has delegated to our CEO the authority to establish and adjust compensation for all employees other than himself. For further discussion of our compensation practices, see "Item 11. Executive Compensation—Compensation Discussion and Analysis" in our 2016 Annual Report on Form 10-K. Consistent with these practices, our current CEO, Mr. Jackson E. Reasor, will establish Mr. Kees' initial base salary for 2018. Mr. Kees will be compensated at his initial 2018 base salary from January 1, 2018 to January 15, 2018. Beginning January 16, 2018, our board of directors and Mr. Kees have verbally agreed that his base salary while serving as Interim CEO will be 120% of his initial 2018 base salary. Mr. Kees' initial 2018 base salary has not yet been determined. This agreement modifies the employment letter, dated November 28, 2005, of Old Dominion Electric Cooperative and agreed and accepted by Mr. Robert L. Kees (filed as exhibit 10.1 to our Form 8-K, File No. 000-50039, on December 1, 2005).

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
101.DEF	XBRL Taxonomy Extension Definition 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 9, 2017

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

Exhibit 31.1

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 9, 2017

/s/ JACKSON E. REASOR

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

Exhibit 31.2

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 9, 2017

/s/ ROBERT L. KEES

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

Exhibit 32.1

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, 2017 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 9, 2017

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

Exhibit 32.2

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, 2017 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 9, 2017

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