

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2016

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)

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

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

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.

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>
Alstom	Alstom Power, Inc.
Bear Island	Bear Island Paper WB LLC
Clover	Clover Power Station
CPCN	Certificate of Public Convenience and Necessity
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
ODEC, We, Our	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
REC	Rappahannock Electric Cooperative
RTO	Regional transmission organization
TEC	TEC Trading, Inc.
VSCC	Virginia State Corporation Commission
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

	June 30, 2016	December 31, 2015
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	\$ 1,741,729	\$ 1,722,477
Less accumulated depreciation	(835,425)	(821,947)
Net Property, plant, and equipment	906,304	900,530
Nuclear fuel, at amortized cost	19,067	15,720
Construction work in progress	658,038	541,323
Net Electric Plant	1,583,409	1,457,573
Investments:		
Nuclear decommissioning trust	151,224	145,715
Lease deposits	103,295	101,816
Unrestricted investments and other	7,099	7,093
Total Investments	261,618	254,624
Current Assets:		
Cash and cash equivalents	1,923	58,383
Accounts receivable	4,810	10,960
Accounts receivable–deposits	—	1,200
Accounts receivable–members	78,589	83,248
Fuel, materials, and supplies	60,830	63,829
Prepayments and other	3,051	4,683
Total Current Assets	149,203	222,303
Deferred Charges:		
Regulatory assets	53,530	61,073
Other	2,229	6,026
Total Deferred Charges	55,759	67,099
Total Assets	<u>\$ 2,049,989</u>	<u>\$ 2,001,599</u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 396,884	\$ 390,976
Non-controlling interest	5,712	5,704
Total Patronage capital and Non-controlling interest	402,596	396,680
Long-term debt	1,018,149	1,017,926
Revolving credit facility	66,600	—
Total long-term debt and revolving credit facility	1,084,749	1,017,926
Total Capitalization	1,487,345	1,414,606
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	131,579	109,887
Accounts payable–members	62,326	98,462
Accrued expenses	7,265	5,580
Deferred energy	38,249	27,835
Total Current Liabilities	267,711	270,056
Deferred Credits and Other Liabilities:		
Asset retirement obligations	120,579	118,200
Obligations under long-term lease	93,774	90,622
Regulatory liabilities	78,740	73,702
Other	1,840	34,413
Total Deferred Credits and Other Liabilities	294,933	316,937
Commitments and Contingencies		
Total Capitalization and Liabilities	<u>\$ 2,049,989</u>	<u>\$ 2,001,599</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)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Operating Revenues	\$ 199,149	\$ 249,341	\$ 455,608	\$ 541,597
Operating Expenses:				
Fuel	30,266	35,652	64,588	79,228
Purchased power	80,999	107,155	220,281	296,433
Transmission	30,772	28,073	62,360	55,158
Deferred energy	8,869	25,671	10,414	1,694
Operations and maintenance	12,618	12,910	25,177	28,835
Administrative and general	10,156	9,974	20,795	20,491
Depreciation and amortization	11,630	11,527	23,168	22,201
Amortization of regulatory asset/(liability), net	646	792	77	1,586
Accretion of asset retirement obligations	1,211	1,292	2,421	2,372
Taxes, other than income taxes	2,098	2,081	4,219	4,192
Total Operating Expenses	<u>189,265</u>	<u>235,127</u>	<u>433,500</u>	<u>512,190</u>
Operating Margin	9,884	14,214	22,108	29,407
Other expense, net	(905)	(823)	(1,949)	(1,687)
Investment income	1,327	1,624	1,465	2,956
Interest charges, net	(7,341)	(12,012)	(15,706)	(24,780)
Income taxes	(2)	(2)	(3)	(2)
Net Margin including Non-controlling interest	2,963	3,001	5,915	5,894
Non-controlling interest	(8)	(9)	(7)	(8)
Net Margin attributable to ODEC	2,955	2,992	5,908	5,886
Patronage Capital - Beginning of Period	393,929	381,991	390,976	379,097
Patronage Capital - End of Period	<u>\$ 396,884</u>	<u>\$ 384,983</u>	<u>\$ 396,884</u>	<u>\$ 384,983</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)

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	\$ 5,915	\$ 5,894
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	23,168	22,201
Other non-cash charges	9,216	9,113
Amortization of lease obligations	3,152	2,944
Interest on lease deposits	(1,479)	(1,441)
Change in current assets	16,640	(13,494)
Change in deferred energy	10,414	1,694
Change in current liabilities	(49,221)	25,469
Change in regulatory assets and liabilities	8,339	3,793
Change in deferred charges-other and deferred credits and other liabilities-other	104	5,239
Net Cash Provided by Operating Activities	<u>26,248</u>	<u>61,412</u>
Investing Activities:		
Purchases of held to maturity securities	—	(130,000)
Proceeds from sale of held maturity securities	—	100,000
Increase in other investments	(1,270)	(2,909)
Electric plant additions	(148,038)	(113,038)
Net Cash Used for Investing Activities	<u>(149,308)</u>	<u>(145,947)</u>
Financing Activities:		
Issuance of long-term debt	—	332,000
Debt issuance costs	—	(1,754)
Draws on revolving credit facility	92,100	104,000
Repayments on revolving credit facility	(25,500)	(190,000)
Net Cash Provided by Financing Activities	<u>66,600</u>	<u>244,246</u>
Net Change in Cash and Cash Equivalents	(56,460)	159,711
Cash and Cash Equivalents - Beginning of Period	58,383	1,424
Cash and Cash Equivalents - End of Period	<u>\$ 1,923</u>	<u>\$ 161,135</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 June 30, 2016, our consolidated results of operations for the three and six months ended June 30, 2016 and 2015, and cash flows for the six months ended June 30, 2016 and 2015. The consolidated results of operations for the three and six months ended June 30, 2016, 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 2015 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 June 30, 2016 and December 31, 2015. 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.

As a result of the adoption of Accounting Standards Update 2015-03 Interest-Imputation of Interest (Subtopic 835-30), we have reclassified debt issuance costs from deferred charges-other to long-term debt in the prior year's Condensed Consolidated Balance Sheet to conform to the current year's presentation.

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 June 30, 2016 and December 31, 2015:

	June 30, 2016	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Observable Inputs (Level 3)
		(in thousands)		
Nuclear decommissioning trust ⁽¹⁾	\$ 48,583	\$ 48,583	\$ —	\$ —
Nuclear decommissioning trust - Net Asset Value ⁽¹⁾⁽²⁾	102,641	—	—	—
Unrestricted investments and other ⁽³⁾	215	—	215	—
Derivatives - gas and power ⁽⁴⁾	1,592	1,592	—	—
Total Financial Assets	\$ 153,031	\$ 50,175	\$ 215	\$ —

	December 31, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Observable Inputs (Level 3)
		(in thousands)		
Nuclear decommissioning trust ⁽¹⁾	\$ 46,051	\$ 46,051	\$ —	\$ —
Nuclear decommissioning trust - Net Asset Value ⁽¹⁾⁽²⁾	99,664	—	—	—
Unrestricted investments and other ⁽³⁾	211	—	211	—
Total Financial Assets	\$ 145,926	\$ 46,051	\$ 211	\$ —
Derivatives - gas and power ⁽⁴⁾	\$ 3,653	\$ 3,653	\$ —	\$ —
Total Financial Liabilities	\$ 3,653	\$ 3,653	\$ —	\$ —

⁽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 which are indexed against NYMEX. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2015 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 2015 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:

Commodity	Unit of Measure	As of June 30, 2016	As of December 31, 2015
		Quantity	Quantity
Natural Gas	MMBTU	9,480,000	10,620,000

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

	Balance Sheet Location	Fair Value	
		As of June 30, 2016	As of December 31, 2015
(in thousands)			
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges-other	\$ 1,592	\$ —
Total derivatives in an asset position		<u>\$ 1,592</u>	<u>\$ —</u>
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	\$ —	\$ 3,653
Total derivatives in a liability position		<u>\$ —</u>	<u>\$ 3,653</u>

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three and Six Months Ended June 30, 2016 and 2015

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of June 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 June 30,		Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Six Months Ended June 30,	
	2016	2015		2016	2015	2016	2015
	(in thousands)			(in thousands)		(in thousands)	
Natural gas futures contracts ⁽¹⁾	\$ 2,093	\$ (4,663)	Fuel	\$ (1,475)	\$ (952)	\$ (2,498)	\$ (1,658)
Purchased power contracts	—	—	Purchased Power	—	—	—	(14)
Total	<u>\$ 2,093</u>	<u>\$ (4,663)</u>		<u>\$ (1,475)</u>	<u>\$ (952)</u>	<u>\$ (2,498)</u>	<u>\$ (1,672)</u>

⁽¹⁾ As of June 30, 2016, includes \$0.5 million of gain on NYMEX contracts designated for July 2016 that were physically sold in June 2016 and the impact on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital has been deferred until July 2016.

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 at June 30, 2016 and December 31, 2015:

Description	Designation	Cost	Gross	Gross	Fair Value	Carrying Value
			Unrealized Gains	Unrealized Losses		
(in thousands)						
June 30, 2016						
Nuclear decommissioning trust ⁽¹⁾						
Debt securities	Available for sale	\$ 43,511	\$ 4,927	\$ —	\$ 48,438	\$ 48,438
Equity securities	Available for sale	72,936	30,993	(1,288)	102,641	102,641
Cash and other	Available for sale	145	—	—	145	145
Total Nuclear Decommissioning Trust		\$ 116,592	\$ 35,920	\$ (1,288)	\$ 151,224	\$ 151,224
Lease Deposits ⁽²⁾						
Government obligations	Held to maturity	\$ 103,295	\$ 4,998	\$ —	\$ 108,293	\$ 103,295
Total Lease Deposits		\$ 103,295	\$ 4,998	\$ —	\$ 108,293	\$ 103,295
Unrestricted investments						
Government obligations	Held to maturity	\$ 2,002	\$ 4	\$ —	\$ 2,006	\$ 2,002
Debt securities	Held to maturity	2,689	18	—	2,707	2,689
Total Unrestricted Investments		\$ 4,691	\$ 22	\$ —	\$ 4,713	\$ 4,691
Other						
Equity securities	Trading	\$ 176	\$ 39	\$ —	\$ 215	\$ 215
Non-marketable equity investments	Equity	2,193	2,071	—	4,264	2,193
Total Other		\$ 2,369	\$ 2,110	\$ —	\$ 4,479	\$ 2,408
						<u>\$ 261,618</u>
December 31, 2015						
Nuclear decommissioning trust ⁽¹⁾						
Debt securities	Available for sale	\$ 42,898	\$ 2,940	\$ —	\$ 45,838	\$ 45,838
Equity securities	Available for sale	72,213	29,164	(1,713)	99,664	99,664
Cash and other	Available for sale	213	—	—	213	213
Total Nuclear Decommissioning Trust		\$ 115,324	\$ 32,104	\$ (1,713)	\$ 145,715	\$ 145,715
Lease Deposits ⁽²⁾						
Government obligations	Held to maturity	\$ 101,816	\$ 4,428	\$ —	\$ 106,244	\$ 101,816
Total Lease Deposits		\$ 101,816	\$ 4,428	\$ —	\$ 106,244	\$ 101,816
Unrestricted investments						
Government obligations	Held to maturity	\$ 2,003	\$ —	\$ (2)	\$ 2,001	\$ 2,003
Debt securities	Held to maturity	2,689	—	(5)	2,684	2,689
Total Unrestricted Investments		\$ 4,692	\$ —	\$ (7)	\$ 4,685	\$ 4,692
Other						
Equity securities	Trading	\$ 175	\$ 36	\$ —	\$ 211	\$ 211
Non-marketable equity investments	Equity	2,190	1,978	—	4,168	2,190
Total Other		\$ 2,365	\$ 2,014	\$ —	\$ 4,379	\$ 2,401
						<u>\$ 254,624</u>

⁽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 2015 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 2015 Annual Report on Form 10-K.

Our investments by classification at June 30, 2016 and December 31, 2015, were as follows:

<u>Description</u>	<u>June 30, 2016</u>		<u>December 31, 2015</u>	
	<u>Cost</u>	<u>Carrying Value</u>	<u>Cost</u>	<u>Carrying Value</u>
	(in thousands)		(in thousands)	
Available for sale	\$ 116,592	\$ 151,224	\$ 115,324	\$ 145,715
Held to maturity	107,986	107,986	106,508	106,508
Equity	2,193	2,193	2,190	2,190
Trading	176	215	175	211
Total	\$ 226,947	\$ 261,618	\$ 224,197	\$ 254,624

Contractual maturities of debt securities at June 30, 2016, 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 ⁽¹⁾	\$ —	\$ —	\$ 48,438	\$ —	\$ 48,438
Held to maturity	3,299	104,687	—	—	107,986
Total	\$ 3,299	\$ 104,687	\$ 48,438	\$ —	\$ 156,424

⁽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. The development, construction, and operation of Wildcat Point are subject to 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 and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We currently anticipate that the project cost will be approximately \$834.3 million, including capitalized interest.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. 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. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through June 30, 2016, we capitalized construction costs related to Wildcat Point totaling \$626.4 million, including \$26.3 million of capitalized interest.

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. We received an initial decision from the hearing judge on April 13, 2015. The hearing judge found many components of the formula rate to be just and reasonable. We believe all components of the formula rate are just and reasonable and addressed the components the hearing judge found to be unjust and unreasonable in our brief on exceptions. Briefs on exceptions to the initial decision and briefs opposing exceptions to the initial decision were filed in 2015. The FERC commissioners have the ultimate authority in this proceeding and they have no timetable to issue a final order. 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 and on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit. We have not recorded a receivable related to this matter.

Revolving Credit Facility

We maintain a \$500.0 million 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 June 30, 2016, we had \$66.6 million outstanding under this facility. At December 31, 2015, we did not have any borrowings outstanding under this facility. At June 30, 2016 and December 31, 2015, we had letters of credit outstanding in the amount of \$5.2 million and \$8.2 million, respectively.

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 the member distribution cooperatives to receive up to the greater of 5% of their power requirements or 5 MW from owned generation or other suppliers. As of March 31, 2016, our member distribution cooperatives collectively received approximately 9 MW under this exception. Beginning May 1, 2016, our member distribution cooperatives collectively receive approximately 60 MW under this exception. We do not anticipate that this 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, a commercial 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. During 2015, Bear Island represented approximately 3.3% of our revenues from our member distribution cooperatives. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows.

New Accounting Pronouncements

We adopted Accounting Standards Update 2015-03 Interest-Imputation of Interest (Subtopic 835-30) for the fiscal year beginning January 1, 2016. Debt issuance costs related to a recognized debt liability are presented on our Condensed Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. Debt issuance costs were previously presented as an asset in deferred charges-other on our Condensed Consolidated Balance Sheet. We have reclassified debt issuance costs in the prior year's Condensed Consolidated Balance Sheet to conform to the current year's presentation. Debt issuance costs related to a recognized debt liability were \$6.6 million and \$6.8 million for June 30, 2016 and December 31, 2015, respectively, and are included as a direct deduction to long-term debt.

We adopted Accounting Standards Update 2015-07 Fair Value Measurement (Topic 820) for the fiscal year beginning January 1, 2016. This update affects the presentation of investments for which fair value is measured at net asset value per share (or its equivalent) as a practical expedient. See Note 2 - Fair Value Measurements above.

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 June 30, 2016, there have been no significant changes in our critical accounting policies as disclosed in our 2015 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 six months ended June 30, 2016, were primarily impacted by milder weather in 2016 as compared to 2015, which contributed to decreased member distribution cooperatives' requirements for power and our need for purchased power, and our continued investment in Wildcat Point. Additionally, our energy sales volume to member distribution cooperatives decreased due to the exercise of a limited exception provision in our wholesale power contract and the election of an alternate supplier under retail choice in Virginia.

- Purchased power expense decreased \$26.2 million, or 24.4%, and \$76.2 million, or 25.7%, for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015, due to decreased volume of purchased energy as well as decreased average cost of purchased energy.
- During the six months ended June 30, 2016, we capitalized \$137.7 million of construction costs related to Wildcat Point. Through June 30, 2016, capitalized construction costs related to Wildcat Point totaled \$626.4 million.
- Energy sales volume to member distribution cooperatives decreased 7.9% and 11.5% for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015. Effective May 1, 2016, one of our member distribution cooperatives elected to purchase 51 MW from an alternate supplier in accordance with a limited exception provision in our wholesale power contract. Additionally, effective June 1, 2016, Bear Island, a commercial customer of REC, elected to purchase its power requirements from an alternate supplier. Collectively, this reduction in our member distribution cooperatives' requirement for power from us accounted for approximately 55% and 16% of the energy sales volume decrease for the three and six months ended June 30, 2016, respectively.

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. The development, construction, and operation of Wildcat Point are subject to 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 and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We currently anticipate that the project cost will be approximately \$834.3 million, including capitalized interest.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. 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. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through June 30, 2016, we capitalized construction costs related to Wildcat Point totaling \$626.4 million, including \$26.3 million of capitalized interest.

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 the member distribution cooperatives to receive up to the greater of 5% of their power requirements or 5 MW from owned generation or other suppliers. As of March 31, 2016, our member distribution cooperatives collectively received approximately 9 MW under this exception. Beginning May 1, 2016, our member distribution cooperatives collectively receive approximately 60 MW under this exception. 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 Wholesale Power Contracts, see “Business—Members—Member Distribution Cooperatives—Wholesale Power Contracts” in Item 1 of our 2015 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, a commercial 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. During 2015, Bear Island represented approximately 3.3% of our revenues from our member distribution cooperatives. 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 2015 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. 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 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 "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. 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 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 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. 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 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.

For the three and six months ended June 30, 2016, we recorded an increase in operating revenues of \$0.9 million and a reduction in operating revenues of \$2.2 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges. For the three and six months ended June 30, 2015, we recorded an increase in operating revenues of \$4.2 million and a reduction in operating revenues of \$6.9 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.

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 six months ended June 30, 2016 and 2015, were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Heating degree days	183	139	31.7%	2,087	2,708	(22.9)%
Cooling degree days	264	453	(41.7)%	264	453	(41.7)%

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 six months ended June 30, 2016 and 2015, were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2016		2015		2016		2015	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	641,421	23.5%	558,291	17.3%	1,360,727	21.3%	1,213,105	16.6%
North Anna	462,414	17.0	481,407	14.9	895,617	14.1	899,790	12.3
Louisa	88,559	3.2	103,019	3.2	152,779	2.4	154,035	2.1
Marsh Run	47,951	1.8	237,471	7.4	131,853	2.1	327,415	4.4
Rock Springs	37,554	1.4	102,331	3.2	37,570	0.6	108,006	1.5
Distributed Generation	57	—	217	—	103	—	554	—
Total Generated	1,277,956	46.9	1,482,736	46.0	2,578,649	40.5	2,702,905	36.9
Purchased:								
Other than renewable:								
Long-term and short-term	1,068,470	39.2	1,468,287	45.6	2,999,768	47.1	3,837,566	52.4
Spot market	216,738	8.0	101,028	3.1	384,446	6.0	361,026	5.0
Total Other than renewable	1,285,208	47.2	1,569,315	48.7	3,384,214	53.1	4,198,592	57.4
Renewable ⁽¹⁾	161,688	5.9	171,055	5.3	409,904	6.4	417,691	5.7
Total Purchased	1,446,896	53.1	1,740,370	54.0	3,794,118	59.5	4,616,283	63.1
Total Available Energy	2,724,852	100.0%	3,223,106	100.0%	6,372,767	100.0%	7,319,188	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 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 to meet system reliability requirements.

Our generating facilities are under dispatch control of PJM. For further discussion on PJM, see “Business—Power Supply Resources—PJM” in Item 1 of our 2015 Annual Report on Form 10-K. 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.

The operational availability of our owned generating resources for the three and six months ended June 30, 2016 and 2015, was as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Clover	78.9%	74.7%	84.4%	75.2%
North Anna	94.9	98.6	90.3	92.9
Louisa	97.8	99.4	98.5	97.1
Marsh Run	93.5	93.0	96.6	96.1
Rock Springs	99.0	99.4	93.1	98.6

The output of Clover and North Anna for the three and six months ended June 30, 2016 and 2015, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Clover	67.9%	59.4%	72.2%	64.8%
North Anna	96.5	100.4	92.1	94.4

The scheduled and unscheduled outages for Clover and North Anna for the three and six months ended June 30, 2016 and 2015, were as follows:

	Clover				North Anna			
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
	June 30,		June 30,		June 30,		June 30,	
	2016	2015	2016	2015	2016	2015	2016	2015
	(in days)		(in days)		(in days)		(in days)	
Scheduled	35.1	39.2	35.1	81.4	9.4	—	35.3	20.5
Unscheduled	3.3	7.0	21.9	8.4	—	2.5	—	5.3
Total	38.4	46.2	57.0	89.8	9.4	2.5	35.3	25.8

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 revenues from sales to non-members; however, in 2016 and 2015, 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 six months ended June 30, 2016 and 2015, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Revenues from sales to:				
Member distribution cooperatives				
Energy revenues ⁽¹⁾	\$ 107,737	\$ 136,386	\$ 257,709	\$ 325,830
Demand revenues	87,860	91,340	181,199	185,460
Total revenues from sales to member distribution cooperatives	195,597	227,726	438,908	511,290
Non-members ⁽²⁾				
Total operating revenues	\$ 199,149	\$ 249,341	\$ 455,608	\$ 541,597
Average cost of energy to member distribution cooperatives (per MWh)	\$ 41.81	\$ 48.76	\$ 43.38	\$ 48.56
Average cost of demand to member distribution cooperatives (per MWh)	34.09	32.66	30.50	27.64
Average total cost to member distribution cooperatives (per MWh)	\$ 75.90	\$ 81.42	\$ 73.88	\$ 76.20

⁽¹⁾ Includes sales of renewable energy credits of \$1.0 million and \$1.6 million for the three and six months ended June 30, 2016, respectively, and \$1.2 million and \$1.4 million for the three and six months ended June 30, 2015, respectively.

⁽²⁾ Includes sales of renewable energy credits of \$0.3 million and \$6.7 million for the three and six months ended June 30, 2016, respectively, and \$6.6 million and \$7.5 million for three and six months ended June 30, 2015, respectively.

Our energy sales in MWh to our member distribution cooperatives and non-members for the three and six months ended June 30, 2016 and 2015, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	2,576,995	2,797,082	5,940,890	6,709,191
Non-members	122,958	407,920	379,225	574,556
Total energy sales	<u>2,699,953</u>	<u>3,205,002</u>	<u>6,320,115</u>	<u>7,283,747</u>

Our energy sales in MWh to our member distribution cooperatives for the three and six months ended June 30, 2016, were 7.9% and 11.5% lower, respectively, as compared to the same periods in 2015. We experienced milder weather during the first half of 2016 as compared to the first half of 2015. Also, effective May 1, 2016, one of our member distribution cooperatives elected to purchase 51 MW from an alternate supplier in accordance with a limited exception provision in our wholesale power contract. Additionally, effective June 1, 2016, Bear Island, a commercial customer of REC, elected to purchase its power requirements from an alternate supplier. Collectively, this reduction in our member distribution cooperatives' requirement for power from us accounted for approximately 55% and 16% of the energy sales volume decrease for the three and six months ended June 30, 2016, respectively.

Our energy sales in MWh to non-members for the three and six months ended June 30, 2016, were 69.9% and 34.0% lower, respectively, as compared to the same periods in 2015 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 months ended June 30, 2016, decreased \$32.1 million, or 14.1%, as compared to the same period in 2015, substantially due to the \$28.6 million, or 21.0%, decrease in energy revenues. The decrease in energy revenues, is due to the 14.3% decrease in the average cost of energy and the 7.9% decrease in the energy sales volume. Total revenues from sales to our member distribution cooperatives for the six months ended June 30, 2016, decreased \$72.4 million, or 14.2%, as compared to the same period in 2015, substantially due to the \$68.1 million, or 20.9%, decrease in energy revenues. The decrease in energy revenues is due to the 11.5% decrease in the energy sales volume and the 10.7% decrease in the average cost of energy.

The average total cost to member distribution cooperatives is affected by changes in our revenues as well as energy sales volumes. Our average total cost to member distribution cooperatives per MWh for the three and six months ended June 30, 2016, was 6.8% and 3.0% lower, respectively, as compared to the same periods in 2015, substantially as a result of the decrease in our total energy rate.

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, 2015	(0.3)
July 1, 2015	(2.9)
January 1, 2016	(5.4)
April 1, 2016	(6.8)

Revenues from sales to non-members for the three months ended June 30, 2016, decreased \$18.1 million, or 83.6%, as compared to the same period in 2015, due to an \$11.8 million decrease in revenue from sales of excess energy and a \$6.3 million decrease in revenue from sales of renewable energy credits. The decrease in revenue from sales of excess energy was due to a 69.9% decrease in the volume of excess energy sales and a 27.4% decrease in the average price of excess energy. Revenues from sales to non-members for the six months ended June 30, 2016, decreased \$13.6 million, or 44.9%, as compared to the same period in 2015, primarily due to a \$12.8 million decrease in revenue from sales of excess energy. The decrease in revenue from sales of excess energy was due to a 34.0% decrease in the volume of excess energy sales and a 32.8% decrease in the average price of excess energy. 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 three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Fuel	\$ 30,266	\$ 35,652	\$ 64,588	\$ 79,228
Purchased power	80,999	107,155	220,281	296,433
Transmission	30,772	28,073	62,360	55,158
Deferred energy	8,869	25,671	10,414	1,694
Operations and maintenance	12,618	12,910	25,177	28,835
Administrative and general	10,156	9,974	20,795	20,491
Depreciation and amortization	11,630	11,527	23,168	22,201
Amortization of regulatory asset/(liability), net	646	792	77	1,586
Accretion of asset retirement obligations	1,211	1,292	2,421	2,372
Taxes, other than income taxes	2,098	2,081	4,219	4,192
Total Operating Expenses	<u>\$ 189,265</u>	<u>\$ 235,127</u>	<u>\$ 433,500</u>	<u>\$ 512,190</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 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 \$45.9 million, or 19.5%, and \$78.7 million, or 15.4%, for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015. The decrease for the three months ended June 30, 2016, was primarily due to decreases in purchased power expense, deferred energy expense and fuel expense, partially offset by the increase in transmission expense. The decrease for the six months ended June 30, 2016, was primarily due to decreases in purchased power expense and fuel expense, partially offset by increases in deferred energy expense and transmission expense.

- Purchased power expense, which includes the cost of purchased energy and capacity, decreased \$26.2 million, or 24.4%, for the three months ended June 30, 2016, as compared to the same period in 2015. The volume of purchased energy decreased 16.9% and the average cost of purchased energy decreased 10.5% for the three months ended June 30, 2016, as compared to the same period in 2015. Purchased power expense decreased \$76.2 million, or 25.7%, for the six months ended June 30, 2016, as compared to the same period in 2015. The volume of purchased energy decreased 17.8% and the average cost of purchased energy decreased 11.9%.
- Deferred energy expense decreased \$16.8 million for the three months ended June 30, 2016, as compared to the same period in 2015. For the three months ended June 30, 2016 and 2015, we over-collected \$8.9 million and \$25.7 million, respectively. Deferred energy expense increased \$8.7 million for the six months ended June 30, 2016, as compared to the same period in 2015. For the six months ended June 30, 2016 and 2015, we over-collected \$10.4 million and \$1.7 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 2015 Annual Report on Form 10-K.
- Fuel expense decreased \$5.4 million, or 15.1%, for the three months ended June 30, 2016, as compared to the same period in 2015, primarily due to the 60.7% decrease in the dispatch of our combustion turbine facilities. Fuel expense decreased \$14.6 million, or 18.5%, for the six months ended June 30, 2016, as compared to the same period in 2015. This decrease was primarily driven by the 45.3% decrease in the dispatch of our combustion turbine facilities and the 6.6% decrease in the average cost of fuel for our combustion turbine facilities.
- Transmission expense increased \$2.7 million, or 9.6%, and \$7.2 million, or 13.1%, for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015, primarily due to increases in PJM charges for network transmission services.

Other Items

Investment Income

Investment income decreased \$0.3 million, or 18.3%, and \$1.5 million, or 50.4%, for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015, primarily due to lower income earned on our nuclear decommissioning trust.

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 six months ended June 30, 2016 and 2015, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Interest on long-term debt	\$ (14,282)	\$ (14,702)	\$ (28,561)	\$ (28,817)
Interest on revolving credit facility	(216)	(124)	(364)	(381)
Other interest	(278)	(133)	(613)	(234)
Total interest charges	(14,776)	(14,959)	(29,538)	(29,432)
Allowance for borrowed funds used during construction	7,435	2,947	13,832	4,652
Interest charges, net	\$ (7,341)	\$ (12,012)	\$ (15,706)	\$ (24,780)

Interest charges, net decreased \$4.7 million, or 38.9%, and \$9.1 million, or 36.6%, for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015, due to the increase in allowance for borrowed funds used during construction (capitalized interest) primarily 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 six months ended June 30, 2016, as compared to the same periods in 2015.

Financial Condition

The principal changes in our financial condition from December 31, 2015 to June 30, 2016, were caused by the increases in construction work in progress, revolving credit facility, accounts payable, and deferred energy, and decreases in accounts payable–members and deferred credits and other liabilities–other.

- Construction work in progress increased \$116.7 million primarily due to expenditures related to Wildcat Point.
- Revolving credit facility increased \$66.6 million due to outstanding borrowings under this facility.
- Accounts payable increased \$21.7 million primarily due to reclassification of the \$28.4 million retainage payable related to Wildcat Point to a current liability.
- Deferred energy increased \$10.4 million as a result of the over-collection of our energy costs in 2016. The deferred energy balance was a liability of \$38.2 million and \$27.8 million at June 30, 2016 and December 31, 2015, respectively.
- Accounts payable–members decreased \$36.1 million primarily due to the decrease in member prepayments and the decrease in amounts owed to our member distribution cooperatives under Margin Stabilization.
- Deferred credits and other liabilities–other decreased \$32.6 million primarily due to the reclassification of the \$28.4 million retainage payable related to Wildcat Point which is now classified as a current liability.

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 six months of 2016 and 2015, our operating activities provided cash flows of \$26.2 million and \$61.4 million, respectively. Operating activities in 2016 were primarily impacted by the following:

- Current liabilities changed \$49.2 million due to changes in accounts payable–members and accounts payable;
- Current assets changed \$16.6 million primarily due to changes in accounts receivable and accounts receivable–members;
- Deferred energy changed \$10.4 million due to an increase in the over-collection of our energy costs in 2016 as compared to 2015; and
- Regulatory assets and liabilities changed \$8.3 million due to changes in derivative activity.

Revolving Credit Facility

We maintain a \$500.0 million 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 June 30, 2016, we had \$66.6 million outstanding under this facility. At December 31, 2015, we did not have any borrowings outstanding under this facility. At June 30, 2016, and December 31, 2015, we had letters of credit outstanding in the amount of \$5.2 million and \$8.2 million, respectively.

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.

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 second quarter of 2016.

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.

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 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. We received an initial decision from the hearing judge on April 13, 2015. The hearing judge found many components of the formula rate to be just and reasonable. We believe all components of the formula rate are just and reasonable and addressed the components the hearing judge found to be unjust and unreasonable in our brief on exceptions. Briefs on exceptions to the initial decision and briefs opposing exceptions to the initial decision were filed in 2015. The FERC commissioners have the ultimate authority in this proceeding and they have no timetable to issue a final order. 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.

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 2015 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. 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 and on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit. We have not recorded a receivable related to this matter.

Amended and Restated Bylaws

Non-substantive administrative changes were made to our Bylaws, and on July 26, 2016, our board of directors approved the Amended and Restated Bylaws as of July 26, 2016, which are filed as Exhibit 3.1 to this quarterly report. We have no equity securities registered under Section 12 of the Securities Exchange Act.

ITEM 6. EXHIBITS

3.1	Amended and Restated Bylaws as of July 26, 2016
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: August 9, 2016

/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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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

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: August 9, 2016

/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: August 9, 2016

/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 June 30, 2016 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: August 9, 2016

/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 June 30, 2016 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: August 9, 2016

/s/ ROBERT L. KEES

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