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 March 31, 2018

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.
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
Wildcat Point	Wildcat Point Generation Facility
WOPC	White Oak Power Constructors
XBRL	Extensible Business Reporting Language

OLD DOMINION ELECTRIC COOPERATIVE

INDEX

OLD DOMINION ELECTRIC COOPERATIVE

PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2018	December 31, 2017
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 1,755,224	$ 1,754,236
Less accumulated depreciation	(902,394)	(891,701)
Net Property, plant, and equipment	852,830	862,535
Nuclear fuel, at amortized cost	15,243	18,089
Construction work in progress	850,043	822,667
Net Electric Plant	1,718,116	1,703,291
Investments:		
Nuclear decommissioning trust	181,590	183,681
Lease deposits	96,890	106,812
Unrestricted investments and other	7,312	7,009
Total Investments	285,792	297,502
Current Assets:		
Cash and cash equivalents	747	4,084
Restricted cash and cash equivalents	10,633	—
Accounts receivable	11,262	10,379
Accounts receivable–members	48,761	83,133
Fuel, materials, and supplies	47,831	52,766
Deferred energy	55,942	3,669
Prepayments and other	3,690	5,274
Total Current Assets	178,866	159,305
Deferred Charges:		
Regulatory assets	43,221	45,284
Other	3,144	3,780
Total Deferred Charges	46,365	49,064
Total Assets	$ 2,229,139	$ 2,209,162
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 418,647	$ 415,384
Non-controlling interest	5,747	5,744
Total Patronage capital and Non-controlling interest	424,394	421,128
Long-term debt	1,198,528	1,198,396
Revolving credit facility	67,000	43,400
Total long-term debt and revolving credit facility	1,265,528	1,241,796
Total Capitalization	1,689,922	1,662,924
Current Liabilities:		
Long-term debt due within one year	40,792	40,792
Accounts payable	81,908	92,259
Accounts payable–members	50,049	59,064
Accrued expenses	23,773	6,391
Regulatory liability–revenue deferral	11,250	15,000
Obligations under long-term lease	105,508	103,683
Total Current Liabilities	313,280	317,189
Deferred Credits and Other Liabilities:		
Asset retirement obligations	126,698	126,470
Regulatory liabilities	97,773	101,237
Other	1,466	1,342
Total Deferred Credits and Other Liabilities	225,937	229,049
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,229,139	$ 2,209,162

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 March 31,	
	2018	2017
	(in thousands)	
Operating Revenues	$ 228,009	$ 189,779
Operating Expenses:		
Fuel	32,916	17,683
Purchased power	167,145	122,116
Transmission	33,146	23,742
Deferred energy	(52,272)	(21,538)
Operations and maintenance	13,401	12,473
Administrative and general	11,602	11,130
Depreciation and amortization	11,678	11,343
Amortization of regulatory asset/liability, net	(2,803)	830
Accretion of asset retirement obligations	1,330	1,255
Taxes, other than income taxes	2,137	2,104
Total Operating Expenses	218,280	181,138
Operating Margin	9,729	8,641
Other expense, net	(1,217)	(949)
Investment income	1,845	1,521
Interest charges, net	(7,090)	(6,244)
Income taxes	(1)	—
Net Margin including Non-controlling interest	3,266	2,969
Non-controlling interest	(3)	(1)
Net Margin attributable to ODEC	3,263	2,968
Patronage Capital - Beginning of Period	415,384	402,857
Patronage Capital - End of Period	$ 418,647	$ 405,825

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

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31,	
	2018	**2017**
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	$ 3,266	$ 2,969
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	11,678	11,343
Other non-cash charges	4,476	4,769
Amortization of lease obligations	1,825	1,685
Interest on lease deposits	(728)	(751)
Change in current assets	40,008	17,156
Change in deferred energy	(52,272)	(21,538)
Change in current liabilities	(505)	6,854
Change in regulatory assets and liabilities	(1,370)	(418)
Change in deferred charges-other and deferred credits and other liabilities-other	(87)	(833)
Net Cash Provided by Operating Activities	6,291	21,236
Investing Activities:		
Purchases of held to maturity securities	(240)	(2,523)
Proceeds from sale of held to maturity securities	10,650	2,000
Increase in other investments	(1,755)	(1,499)
Electric plant additions	(30,995)	(51,290)
Net Cash Used for Investing Activities	(22,340)	(53,312)
Financing Activities:		
Debt issuance costs	(255)	—
Draws on revolving credit facility	155,750	183,250
Repayments on revolving credit facility	(132,150)	(153,500)
Net Cash Provided by Financing Activities	23,345	29,750
Net Change in Cash and Cash Equivalents and Restricted Cash and Cash Equivalents	7,296	(2,326)
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - Beginning of Period	4,084	2,946
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - End of Period	$ 11,380	$ 620

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

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 March 31, 2018, our consolidated results of operations for the three months ended March 31, 2018 and 2017, and cash flows for the three months ended March 31, 2018 and 2017. The consolidated results of operations for the three months ended March 31, 2018, 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 2017 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 eleven Class A members are 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 March 31, 2018 and December 31, 2017. 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 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 March 31, 2018 and December 31, 2017:

	March 31, 2018	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]	$ 58,787	$ 58,787	$ —	$ —
Nuclear decommissioning trust - net asset value [1][2]	122,803	—	—	—
Unrestricted investments and other [3]	324	—	324	—
Total Financial Assets	$ 181,914	$ 58,787	$ 324	$ —
Derivatives - gas and power [4]	$ 1,142	$ 639	$ 503	$ —
Total Financial Liabilities	$ 1,142	$ 639	$ 503	$ —

	December 31, 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]	$ 59,723	$ 59,723	$ —	$ —
Nuclear decommissioning trust - net asset value [1][2]	123,958	—	—	—
Unrestricted investments and other [3]	308	—	308	—
Total Financial Assets	$ 183,989	$ 59,723	$ 308	$ —
Derivatives - gas and power [4]	$ 1,034	$ 975	$ 59	$ —
Total Financial Liabilities	$ 1,034	$ 975	$ 59	$ —

[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 2017 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 2017 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 March 31, 2018	As of December 31, 2017
Natural Gas	MMBTU	23,050,000	23,700,000

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 March 31, 2018	As of December 31, 2017
		(in thousands)	
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 1,142	$ 1,034
Total derivatives in a liability position		$ 1,142	$ 1,034

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three Months Ended March 31, 2018 and 2017

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of March 31,		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 March 31,	
	2018	2017		2018	2017
	(in thousands)			(in thousands)	
Natural gas futures contracts	$ (1,260)	$ 4,519	Fuel	$ (804)	$ (131)
Total	$ (1,260)	$ 4,519		$ (804)	$ (131)

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 March 31, 2018 and December 31, 2017:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
				(in thousands)		
March 31, 2018						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 54,743	$ 3,759	$ —	$ 58,502	$ 58,502
Equity securities	Available for sale	79,193	44,398	(788)	122,803	122,803
Cash and other	Available for sale	285	—	—	285	285
Total Nuclear Decommissioning Trust		$ 134,221	$ 48,157	$ (788)	$ 181,590	$ 181,590
Lease Deposits [2]						
Government obligations	Held to maturity	$ 96,890	$ 419	$ —	$ 97,309	$ 96,890
Total Lease Deposits		$ 96,890	$ 419	$ —	$ 97,309	$ 96,890
Unrestricted investments						
Government obligations	Held to maturity	$ 2,346	$ —	$ (12)	$ 2,334	$ 2,346
Debt securities	Held to maturity	2,457	—	(6)	2,451	2,457
Total Unrestricted Investments		$ 4,803	$ —	$ (18)	$ 4,785	$ 4,803
Other						
Equity securities	Trading	$ 241	$ 83	$ —	$ 324	$ 324
Non-marketable equity investments	Equity	2,185	2,087	—	4,272	2,185
Total Other		$ 2,426	$ 2,170	$ —	$ 4,596	$ 2,509
						$ 285,792
December 31, 2017						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 54,375	$ 5,029	$ —	$ 59,404	$ 59,404
Equity securities	Available for sale	77,838	46,474	(354)	123,958	123,958
Cash and other	Available for sale	319	—	—	319	319
Total Nuclear Decommissioning Trust		$ 132,532	$ 51,503	$ (354)	$ 183,681	$ 183,681
Lease Deposits [2]						
Government obligations	Held to maturity	$ 106,812	$ 776	$ —	$ 107,588	$ 106,812
Total Lease Deposits		$ 106,812	$ 776	$ —	$ 107,588	$ 106,812
Unrestricted investments						
Government obligations	Held to maturity	$ 2,344	$ —	$ (13)	$ 2,331	$ 2,344
Debt securities	Held to maturity	2,217	—	(3)	2,214	2,217
Total Unrestricted Investments		$ 4,561	$ —	$ (16)	$ 4,545	$ 4,561
/						
Other						
Equity securities	Trading	$ 223	$ 85	$ —	$ 308	$ 308
Non-marketable equity investments	Equity	2,140	2,066	—	4,206	2,140
Total Other		$ 2,363	$ 2,151	$ —	$ 4,514	$ 2,448
						$ 297,502

(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 2017 Annual Report on Form 10-K. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or regulatory asset, 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 2017 Annual Report on Form 10-K.

Our investments by classification as of March 31, 2018 and December 31, 2017, were as follows:

Description	March 31, 2018 Cost	March 31, 2018 Carrying Value	December 31, 2017 Cost	December 31, 2017 Carrying Value
	(in thousands)		(in thousands)	
Available for sale	$ 134,221	$ 181,590	$ 132,532	$ 183,681
Held to maturity	101,693	101,693	111,373	111,373
Equity	2,185	2,185	2,140	2,140
Trading	241	324	223	308
Total	$ 238,340	$ 285,792	$ 246,268	$ 297,502

Contractual maturities of debt securities as of March 31, 2018, 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]	$ —	$ —	$ 58,502	$ —	$ 58,502
Held to maturity	101,098	595	—	—	101,693
Total	$ 101,098	$ 595	$ 58,502	$ —	$ 160,195

[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

On April 17, 2018, Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, achieved commercial operation and was available for dispatch by PJM.

The facility originally was scheduled to become operational in mid-2017. WOPC, the EPC contractor, claims the delay was 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 against us and believe they are without merit. We have not recorded any liability related to these claims as we do not believe any liability is estimable or probable. We intend to vigorously defend against these claims.

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. On November 16, 2017, the United States District Court for the Eastern District of Virginia ordered that the WOPC complaint against Alstom and us, our complaint against WOPC, and a separate complaint filed by WOPC against Mitsubishi on May 9, 2017, be consolidated into one case.

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.

Through March 31, 2018, we capitalized construction costs related to Wildcat Point totaling $814.8 million, which includes $86.9 million of capitalized interest and is offset by $53.2 million of liquidated damages. We anticipate the final capitalized construction costs to be approximately $845 million.

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 we previously suggested and FERC directed in the January 19, 2017 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. On March 22, 2018, FERC issued an order denying Bear Island's request for rehearing and accepted our February 21, 2017 compliance filing that revised the formula rate as directed by FERC's January 19, 2017 order. We filed a refund report with FERC on April 23, 2018, that calculated the difference between rates charged under our rate schedule since January 1, 2014, and rates that would have been charged under the revised rate schedule submitted in our February 21, 2017 compliance filing. Once the refund report is approved, we believe the refund will result in a reallocation of costs among our member distribution cooperatives and will not result in any change to our total operating revenues.

Revolving Credit Facility

We maintain a 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. Commitments under this syndicated credit agreement extend until March 3, 2023. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through March 3, 2023. As of March 31, 2018, we had outstanding under this facility $67.0 million in borrowings and $20.0 million in letters of credit. As of December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings and $12.0 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 its owned generation or from 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. As of May 1, 2018, there are approximately 66 MW remaining that can be utilized under this exception. 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	109

We do not anticipate that either the current or potential full utilization of this exception will have a material impact on our financial condition, results of operations, or cash flows.

Cash and Cash Equivalents

The following table provides a reconciliation of cash and cash equivalents and restricted cash and cash equivalents reported within the Condensed Consolidated Balance Sheet that sum to the total of the same amounts shown in the Condensed Consolidated Statement of Cash Flows:

	As of March 31, 2018	As of March 31, 2017
	(in thousands)	
Cash and cash equivalents	$ 747	$ 620
Restricted cash and cash equivalents	10,633	—
	$ 11,380	$ 620

Restricted cash and cash equivalents relates to funds restricted for payments related to our obligations under a long-term lease transaction.

New Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09 Revenue from Contracts with Customers (Topic 606). 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 bill our member distribution cooperatives monthly and each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract. We transfer control of the electricity over time and our member distribution cooperatives simultaneously receive and consume the benefits of the electricity. The amount we invoice our member distribution cooperatives on a monthly basis corresponds directly to the value to the member distribution cooperatives of our performance, which is determined by our formula rate included in the wholesale power contract. We also sell excess energy and renewable energy credits to non-members at prevailing market prices as control is transferred. We have completed our contract review of our wholesale power and other contracts within the scope of Topic 606, and have finalized our analysis. We have not identified any material impact to our recognition of revenue from the sale of power to our member distribution cooperatives or non-members. We adopted this standard effective January 1, 2018, using the modified retrospective approach. There was no material impact to our recognition of revenue from the sale of power to our member distribution cooperatives or non-members, and there has been no cumulative effect adjustment recognized.

Our operating revenues for the three months ended March 31, 2018 were as follows:

	Three Months Ended March 31, 2018
	(in thousands)
Member distribution cooperatives	
Sales to member distribution cooperatives, excluding renewable energy credit sales	$ 224,291
Renewable energy credit sales to member distribution cooperatives	11
Total Sales to Member Distribution Cooperatives	$ 224,302
Non-members	
Sales to non-members, excluding renewable energy credit sales	$ 3,142
Renewable energy credit sales to non-members	565
Total sales to Non-members	$ 3,707
Total operating revenues	$ 228,009

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.

In November 2016, the FASB issued Accounting Standards Update 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash. This update revised accounting guidance for the classification and presentation of restricted cash in the statement of cash flows. We adopted this update effective January 1, 2018, and it requires a reconciliation of cash and cash equivalents and restricted cash and cash equivalents within the Condensed Consolidated Balance Sheet and the amounts shown in the Condensed Consolidated Statement of Cash Flows. See Cash and Cash Equivalents above.

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 March 31, 2018, there have been no significant changes in our critical accounting policies as disclosed in our 2017 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 months ended March 31, 2018, were primarily impacted by colder weather that resulted in increases in our member distribution cooperatives' requirements for power, purchased power expense, and the dispatch of our generating facilities. Additionally, we increased our total energy rate 11.1%, effective January 1, 2018.

- Our energy revenues from sales to our member distribution cooperatives increased $29.8 million, or 27.4%, due to the 14.6% increase in our energy sales in MWh and the 11.1% increase in the average cost of energy sold to our member distribution cooperatives.
- Purchased power expense increased $45.0 million, or 36.9%, primarily as a result of the 29.5% increase in the average cost of purchased energy and the 8.1% increase in the volume of purchased energy.
- Generation from our combustion turbine facilities and Clover increased 309.0% and 28.0%, respectively, primarily due to PJM's economic dispatch of these facilities. These factors contributed to the $15.2 million, or 86.1%, increase in fuel expense.

- As a result of higher costs, we under-collected energy costs by $52.3 million in the first quarter of 2018. As of March 31, 2018, our deferred energy balance was $55.9 million under-collected. To address the under-collection, we increased our total energy rate 3.7% effective April 1, 2018.

Wildcat Point Generation Facility

On April 17, 2018, Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, achieved commercial operation and was available for dispatch by PJM.

The facility originally was scheduled to become operational in mid-2017. WOPC, the EPC contractor, claims the delay was 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 against us and believe they are without merit. We have not recorded any liability related to these claims as we do not believe any liability is estimable or probable. We intend to vigorously defend against these claims.

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. On November 16, 2017, the United States District Court for the Eastern District of Virginia ordered that the WOPC complaint against Alstom and us, our complaint against WOPC, and a separate complaint filed by WOPC against Mitsubishi on May 9, 2017, be consolidated into one case.

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.

Through March 31, 2018, we capitalized construction costs related to Wildcat Point totaling $814.8 million, which includes $86.9 million of capitalized interest and is offset by $53.2 million of liquidated damages. We anticipate the final capitalized construction costs to be approximately $845 million.

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 its owned generation or from 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. As of May 1, 2018, there are approximately 66 MW remaining that can be utilized under this exception. 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	109

We do not anticipate that either the current or potential full 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 2017 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. On December 2, 2013, FERC accepted our formula rate effective January 1, 2014, subject to refund, and established hearing and settlement procedures. On January 19, 2017, FERC directed us to submit a compliance filing making certain revisions to the formula rate. These revisions to the formula rate did not change our overall revenue requirements. On March 22, 2018, FERC accepted our compliance filing and required us to file a refund report to calculate the difference between rates charged under our rate schedule since January 1, 2014, and rates that would have been charged under the revised rate schedule submitted in our compliance filing. Once the refund report is approved, we believe the refund will result in a reallocation of costs among our member distribution cooperatives and will not result in any change to our operating revenues. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part II, Item 1.

Our formula rate 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 (collectively referred to as the total energy 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. We can revise the energy adjustment rate during the year if it becomes apparent that the total energy rate is over-collecting or under-collecting our actual and anticipated energy costs. Any revision to the energy adjustment rate requires board approval and that the resulting change to the total energy rate is at least 2%.

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 – designed to collect capacity costs in PJM that PJM allocates to ODEC and all other PJM members; and
- remaining owned capacity service rate – designed to collect 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. The formula rate permits us to adjust revenues from the member distribution cooperatives to equal our actual total demand costs incurred, including a net margin attributable to ODEC equal to 20% of actual interest charges, plus additional equity contributions approved by our board. We make these adjustments utilizing Margin Stabilization.

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. 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.

For the three months ended March 31, 2018 and 2017, we reduced revenues utilizing Margin Stabilization as follows:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Margin Stabilization adjustment	$ 19,647	$ 18,034

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 2017 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.

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 months ended March 31, 2018, were as follows:

	Three Months Ended March 31,		
	2018	2017	Change
Heating degree days	1,874	1,632	14.8%
Cooling degree days	—	—	—

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 months ended March 31, 2018 and 2017, were as follows:

	Three Months Ended March 31,			
	2018		2017	
	(in MWh and percentages)			
Generated:				
Clover	452,094	12.8%	353,071	11.2%
North Anna	430,539	12.1	486,057	15.5
Louisa	91,466	2.6	24,928	0.8
Marsh Run	139,897	3.9	32,212	1.0
Rock Springs	2,327	0.1	—	—
Distributed Generation	476	—	26	—
Total Generated	1,116,799	31.5	896,294	28.5
Purchased:				
Other than renewable:				
Long-term and short-term	1,410,669	39.8	1,636,649	52.1
Spot market	766,772	21.6	360,330	11.5
Total Other than renewable	2,177,441	61.4	1,996,979	63.6
Renewable (1)	251,759	7.1	249,164	7.9
Total Purchased	2,429,200	68.5	2,246,143	71.5
Total Available Energy	3,545,999	100.0%	3,142,437	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 2017 Annual Report on Form 10-K.

Operational Availability

The operational availability of our owned generating resources for the three months ended March 31, 2018 and 2017, was as follows:

	Three Months Ended March 31,	
	2018	2017
Clover	93.9%	75.6%
North Anna	88.3	99.2
Louisa	99.7	99.8
Marsh Run	99.3	99.5
Rock Springs	84.5	91.0

Capacity Factor

The output of Clover and North Anna for the three months ended March 31, 2018 and 2017, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended March 31,	
	2018	**2017**
Clover	49.2%	38.6%
North Anna	90.9	102.6

Outages

The scheduled and unscheduled outages for Clover and North Anna for the three months ended March 31, 2018 and 2017, were as follows:

	Clover Three Months Ended March 31,		North Anna Three Months Ended March 31,	
	2018	**2017**	**2018**	**2017**
	(in days)		(in days)	
Scheduled	—	28.0	21.0	—
Unscheduled	11.1	15.9	—	1.4
Total	11.1	43.9	21.0	1.4

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

Revenues from 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.

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 months ended March 31, 2018 and 2017, were as follows:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(in thousands)	
Revenues from sales to:		
Member distribution cooperatives		
Energy revenues	$ 138,735	$ 108,934
Demand revenues	85,567	76,368
Total revenues from sales to member distribution cooperatives	224,302	185,302
Non-members	3,707	4,477
Total operating revenues	$ 228,009	$ 189,779
Energy sales to:	(in MWh)	
Member distribution cooperatives	3,457,036	3,016,354
Non-members	80,287	121,112
Total energy sales	3,537,323	3,137,466
Average cost of energy to member distribution cooperatives (per MWh)	$ 40.13	$ 36.11
Average total cost to member distribution cooperatives (per MWh)	$ 64.88	$ 61.43

Sales of power and renewable energy credits for the three months ended March 31, 2018 and 2017, were as follows:

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(in thousands)	
Member distribution cooperatives		
Sales to member distribution cooperatives, excluding renewable energy credit sales	$ 224,291	$ 185,289
Renewable energy credit sales to member distribution cooperatives	11	13
Total Sales to Member Distribution Cooperatives	$ 224,302	$ 185,302
Non-members		
Sales to non-members, excluding renewable energy credit sales	$ 3,142	$ 3,548
Renewable energy credit sales to non-members	565	929
Total sales to Non-members	$ 3,707	$ 4,477

Member Distribution Cooperatives

For the three months ended March 31, 2018, total revenues from sales to our member distribution cooperatives were 21.0% higher, as compared to the same period in 2017, due to increases in energy and demand revenues. Energy revenues increased $29.8 million, or 27.4%, for the three months ended March 31, 2018, as compared to the same period in 2017 due to the increase in energy sales in MWh to our member distribution cooperatives and an increase in the average cost of energy sold to our member distribution cooperatives. The energy sales in MWh to our member distribution cooperatives increased 14.6% and the average cost of energy sold to our member distribution cooperatives increased 11.1%. The average cost of energy sold to our member distribution cooperatives was impacted by the 11.1% total energy rate increase we implemented January 1, 2018. Demand revenues increased $9.2 million, or 12.0%, for the three months ended March 31, 2018, as compared to the same period in 2017, primarily due to the increase in transmission expense.

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:

Date	% Change
January 1, 2017	(6.7)
January 1, 2018	11.1
April 1, 2018	3.7

Non-members

Revenues from sales to non-members for the three months ended March 31, 2018, decreased $0.8 million, or 17.2%, as compared to the same period in 2017. 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 months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Fuel	$ 32,916	$ 17,683
Purchased power	167,145	122,116
Transmission	33,146	23,742
Deferred energy	(52,272)	(21,538)
Operations and maintenance	13,401	12,473
Administrative and general	11,602	11,130
Depreciation and amortization	11,678	11,343
Amortization of regulatory asset/liability, net	(2,803)	830
Accretion of asset retirement obligations	1,330	1,255
Taxes, other than income taxes	2,137	2,104
Total Operating Expenses	$ 218,280	$ 181,138

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 increased $37.1 million, or 20.5%, for the three months ended March 31, 2018, respectively, as compared to the same period in 2017. The increase for the three months ended March 31, 2018, was primarily due to increases in purchased power expense, fuel expense, and transmission expense; partially offset by the decrease in deferred energy.

- Purchased power expense, which includes the cost of purchased energy and capacity, increased $45.0 million, or 36.9%, for the three months ended March 31, 2018, as compared to the same period in 2017. Purchased energy increased $45.5 million due to the 29.5% increase in the average cost of purchased energy and the 8.1% increase in the volume of purchased energy.

- Fuel expense increased $15.2 million, or 86.1%, for the three months ended March 31, 2018, as compared to the same period in 2017. Generation from our combustion turbine facilities and Clover increased 309.0% and 28.0%, respectively, primarily due to PJM's economic dispatch of these facilities.
- Transmission expense increased $9.4 million, or 39.6%, for the three months ended March 31, 2018, as compared to the same period in 2017, primarily due to increases in PJM charges for network transmission services.
- Deferred energy expense decreased $30.7 million for the three months ended March 31, 2018, as compared to the same period in 2017. For the three months ended March 31, 2018 and 2017, we under-collected $52.3 million and $21.5 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 2017 Annual Report on Form 10-K.

Other Items

Investment Income

Investment income was relatively flat for the three months ended March 31, 2018, as compared to the same period in 2017.

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 months ended March 31, 2018 and 2017, were as follows:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Interest on long-term debt	$ (15,554)	$ (13,782)
Interest on revolving credit facility	(601)	(879)
Other interest	(158)	(179)
Total interest charges	(16,313)	(14,840)
Allowance for borrowed funds used during construction	9,223	8,596
Interest charges, net	$ (7,090)	$ (6,244)

Interest charges, net increased $0.8 million for the three months ended March 31, 2018, as compared to the same period in 2017, substantially due to the increase in interest on long-term debt, partially offset by the increase in allowance for borrowed funds used during construction (capitalized interest) related to Wildcat Point. We issued $250.0 million of long-term debt in July 2017.

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 months ended March 31, 2018, as compared to the same period in 2017.

Financial Condition

The principal changes in our financial condition from December 31, 2017 to March 31, 2018, were caused by increases in deferred energy, construction work in progress, revolving credit facility, and accrued expenses, and the decrease in accounts receivable–members.

- Deferred energy increased $52.3 million as a result of the under-collection of our energy costs in 2018. The deferred energy balance was $3.7 million and $55.9 million at December 31, 2017 and March 31, 2018, respectively.

- Construction work in progress increased $27.4 million primarily due to expenditures related to Wildcat Point.
- Revolving credit facility increased $23.6 million due to outstanding borrowings under this facility.
- Accrued expenses increased $16.3 million primarily due to accrued interest on long-term debt.
- Accounts receivable–members decreased $34.4 million primarily due to the $34.1 million credited to our member distribution cooperatives' March 2018 wholesale power invoices for the 2017 Margin Stabilization adjustment.

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 three months of 2018 and 2017, our operating activities provided cash flows of $6.3 million and $21.2 million, respectively. Operating activities in 2018 were primarily impacted by the following:

- Deferred energy changed $52.3 million due to the under-collection of our energy costs in 2018; and
- Current assets changed $40.0 million primarily due to the change in accounts receivable–members.

Revolving Credit Facility

We maintain a 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. Commitments under this syndicated credit agreement extend until March 3, 2023. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through March 3, 2023. As of March 31, 2018, we had outstanding under this facility $67.0 million in borrowings and $20.0 million in letters of credit. As of December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings and $12.0 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.

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 first quarter of 2018.

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 we previously suggested and FERC directed in the January 19, 2017 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. On March 22, 2018, FERC issued an order denying Bear Island's request for rehearing and accepted our February 21, 2017 compliance filing that revised the formula rate as directed by FERC's January 19, 2017 order. We filed a refund report with FERC on April 23, 2018, that calculated the difference between rates charged under our rate schedule since January 1, 2014, and rates that would have been charged under the revised rate schedule submitted in our February 21, 2017 compliance filing. Once the refund report is approved, we believe the refund will result in a reallocation of costs among our member distribution cooperatives and will not result in any change to our operating revenues.

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 United States Court of Appeals for the District of Columbia Circuit, and on October 24, 2017, the court heard oral arguments. Additionally, we have followed the legal process to preserve our right to pursue this matter in the Commonwealth of Virginia. We have not recorded a receivable related to this matter.

Wildcat Point

On April 17, 2018, Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, achieved commercial operation and was available for dispatch by PJM.

The facility originally was scheduled to become operational in mid-2017. WOPC, the EPC contractor, claims the delay was 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 against us and believe they are without merit. We have not recorded any liability related to these claims as we do not believe any liability is estimable or probable. We intend to vigorously defend against these claims.

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. On November 16, 2017, the United States District Court for the Eastern District of Virginia ordered that the WOPC complaint against Alstom and us, our complaint against WOPC, and a separate complaint filed by WOPC against Mitsubishi on May 9, 2017, be consolidated into one case.

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 2017 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 6. EXHIBITS

31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a)
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-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: May 9, 2018

/s/ Robert L. Kees

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

Exhibit 31.1

CERTIFICATIONS

I, Marcus M. Harris, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;

2. Based on my knowledge, this 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-15(e) and 15d-15(e) 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 designed 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 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 of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses 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: May 9, 2018

/s/ MARCUS M. HARRIS

Marcus M. Harris
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 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-15(e) and 15d-15(e) 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 designed 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 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 of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses 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: May 9, 2018

/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 March 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Marcus M. Harris, 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: May 9, 2018

/s/ MARCUS M. HARRIS
Marcus M. Harris
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 March 31, 2018 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: May 9, 2018

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