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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2019

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 every Interactive Data File required to be submitted 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 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 ☒

Securities registered pursuant to Section 12(b) of the Act: NONE

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.
ASU	Accounting Standards Update
Clover	Clover Power Station
CO_2	Carbon dioxide
EPRS	Essential Power Rock Springs, LLC
EPC	Engineering, procurement, and construction
FASB	Financial Accounting Standards Board
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
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional transmission organization
TEC	TEC Trading, Inc.
VAPCB	Virginia Air Pollution Control Board
Virginia Power	Virginia Electric and Power Company
Wildcat Point	Wildcat Point Generation Facility
WOPC	White Oak Power Constructors
XBRL	Extensible Business Reporting Language

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OLD DOMINION ELECTRIC COOPERATIVE

PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2019	December 31, 2018
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 2,466,172	$ 2,454,568
Less accumulated depreciation	(915,175)	(869,478)
Net Property, plant, and equipment	1,550,997	1,585,090
Nuclear fuel, at amortized cost	15,360	14,694
Construction work in progress	38,882	40,112
Net Electric Plant	1,605,239	1,639,896
Investments:		
Nuclear decommissioning trust	198,075	173,951
Unrestricted investments and other	7,570	8,066
Total Investments	205,645	182,017
Current Assets:		
Cash and cash equivalents	22,583	8,649
Restricted cash and cash equivalents	24,130	14,329
Accounts receivable	11,311	9,310
Accounts receivable–members	88,727	84,410
Fuel, materials, and supplies	60,828	54,494
Deferred energy	8,214	26,069
Prepayments and other	3,802	4,648
Total Current Assets	219,595	201,909
Deferred Charges:		
Regulatory assets	46,624	38,016
Other	21,416	5,063
Total Deferred Charges	68,040	43,079
Total Assets	$ 2,098,519	$ 2,066,901
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 438,241	$ 428,663
Non-controlling interest	5,830	5,776
Total Patronage capital and Non-controlling interest	444,071	434,439
Long-term debt	1,158,530	1,158,141
Total Capitalization	1,602,601	1,592,580
Current Liabilities:		
Long-term debt due within one year	40,792	40,792
Accounts payable	120,381	113,477
Accounts payable–members	47,644	57,549
Accrued expenses	23,327	5,997
Regulatory liability–deferral of gain on sale of asset	9,431	37,723
Total Current Liabilities	241,575	255,538
Deferred Credits and Other Liabilities:		
Asset retirement obligations	134,642	130,488
Regulatory liabilities	105,872	87,300
Other	13,829	995
Total Deferred Credits and Other Liabilities	254,343	218,783
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,098,519	$ 2,066,901

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

OLD DOMINION ELECTRIC COOPERATIVE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Operating Revenues	$ 252,729	$ 257,586	$ 708,493	$ 712,247
Operating Expenses:				
Fuel	51,000	65,134	143,921	147,573
Purchased power	83,851	71,059	238,828	299,645
Transmission	38,107	39,916	121,476	105,145
Deferred energy	15,403	17,482	17,855	(18,086)
Operations and maintenance	23,721	15,236	59,638	48,236
Administrative and general	11,358	11,593	38,395	34,848
Depreciation and amortization	17,207	17,057	51,539	45,818
Amortization of regulatory asset/(liability), net	(9,163)	(2,816)	(26,342)	(7,457)
Accretion of asset retirement obligations	1,386	1,330	4,154	3,991
Taxes, other than income taxes	2,350	2,597	7,185	7,315
Total Operating Expenses	235,220	238,588	656,649	667,028
Operating Margin	17,509	18,998	51,844	45,219
Other income (expense), net	(41)	(689)	(43)	(2,962)
Investment income	1,358	1,949	5,369	6,470
Interest income on North Anna Unit 3 cost recovery	—	—	—	141
Interest charges, net	(15,648)	(16,862)	(47,519)	(38,874)
Income taxes	(4)	—	(19)	(4)
Net Margin including Non-controlling interest	3,174	3,396	9,632	9,990
Non-controlling interest	(16)	—	(54)	(12)
Net Margin attributable to ODEC	3,158	3,396	9,578	9,978
Patronage Capital - Beginning of Period	435,083	421,966	428,663	415,384
Patronage Capital - End of Period	$ 438,241	$ 425,362	$ 438,241	$ 425,362

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

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30,	
	2019	**2018**
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	$ 9,632	$ 9,990
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	51,539	45,818
Other non-cash charges	12,674	13,820
Amortization of lease obligations	—	4,468
Interest on lease deposits	—	(1,671)
Change in current assets	(11,806)	4,613
Change in deferred energy	17,855	(18,086)
Change in current liabilities	18,063	10,638
Change in regulatory assets and liabilities	(38,127)	(2,364)
Change in deferred charges-other and deferred credits and other liabilities-other	(3,225)	(2,285)
Net Cash Provided by Operating Activities	56,605	64,941
Investing Activities:		
Purchases of held to maturity securities	(2,875)	(362)
Proceeds from sale of held to maturity securities	3,078	76,137
Purchases of available for sale securities	(53,828)	—
Proceeds from sale of available for sale securities	53,828	—
Increase in other investments	(4,069)	(6,116)
Electric plant additions	(28,747)	(48,431)
Proceeds from sale of asset	—	115,000
Net Cash (Used for)/Provided by Investing Activities	(32,613)	136,228
Financing Activities:		
Debt issuance costs	(257)	(255)
Payment of obligation under long-term lease	—	(75,951)
Draws on revolving credit facility	167,250	372,950
Repayments on revolving credit facility	(167,250)	(416,350)
Net Cash Used for Financing Activities	(257)	(119,606)
Net Change in Cash and Cash Equivalents and Restricted Cash and Cash Equivalents	23,735	81,563
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - Beginning of Period	22,978	4,084
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - End of Period	$ 46,713	$ 85,647

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. General

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. In the opinion of management, the accompanying unaudited condensed consolidated financial statements contain all adjustments, which include only normal recurring adjustments, necessary for a fair statement of our consolidated financial position as of September 30, 2019, our consolidated results of operations for the three and nine months ended September 30, 2019 and 2018, and cash flows for the nine months ended September 30, 2019 and 2018. The consolidated results of operations for the three and nine months ended September 30, 2019, 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 2018 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 $5.8 million as of September 30, 2019 and December 31, 2018. The income taxes reported on our Condensed Consolidated Statements 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.

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 did not have any other comprehensive income for the periods presented.

2. Fair Value Measurements

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

The following table summarizes our financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2019 and December 31, 2018:

	September 30, 2019	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]	$ 64,128	$ 64,128	$ —	$ —
Nuclear decommissioning trust - net asset value [1][2]	133,947	—	—	—
Unrestricted investments and other [3]	98	—	98	—
Derivatives - gas and power [4]	1,210	—	157	1,053
Total Financial Assets	$ 199,383	$ 64,128	$ 255	$ 1,053
Derivatives - gas and power [4]	$ 13,510	$ 13,510	$ —	$ —
Total Financial Liabilities	$ 13,510	$ 13,510	$ —	$ —

	December 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]	$ 59,150	$ 59,150	$ —	$ —
Nuclear decommissioning trust - net asset value [1][2]	114,801	—	—	—
Unrestricted investments and other [3]	394	—	394	—
Derivatives - gas and power [4]	784	—	784	—
Total Financial Assets	$ 175,129	$ 59,150	$ 1,178	$ —
Derivatives - gas and power [4]	$ 591	$ 591	$ —	$ —
Total Financial Liabilities	$ 591	$ 591	$ —	$ —

(1) For additional information about our nuclear decommissioning trust, see Note 4—Investments 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 and Level 2) and financial transmission rights (Level 3). Level 1 are indexed against NYMEX. Level 2 are valued by ACES using observable market inputs for similar transactions. Level 3 are valued by ACES using unobservable market inputs, including situations where there is little market activity. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2018 Annual Report on Form 10-K.

We recorded the fair value of financial transmission rights (Level 3) in 2019 and as of September 30, 2019, the fair value was $1.1 million. Sensitivity in the market price of financial transmission rights could impact the fair value. The unrealized gain (change in market value) was reported in regulatory assets in our Condensed Consolidated Balance Sheet as of September 30, 2019.

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 2018 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.

Outstanding derivative instruments, excluding contracts accounted for as normal purchase/normal sale, were as follows:

		Quantity	
Commodity	**Unit of Measure**	**As of September 30, 2019**	**As of December 31, 2018**
Natural gas	MMBTU	78,230,000	36,790,000
Purchased power - financial transmission rights	MWh	7,761,538	—

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

		Fair Value	
	Balance Sheet Location	**As of September 30, 2019**	**As of December 31, 2018**
		(in thousands)	
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges-other	$ 157	$ 784
Financial transmission rights	Deferred charges-other	1,053	—
Total derivatives in an asset position		$ 1,210	$ 784
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 13,510	$ 591
Total derivatives in a liability position		$ 13,510	$ 591

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three and Nine Months Ended September 30, 2019 and 2018

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of September 30,		Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income	Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018		2019	2018	2019	2018
	(in thousands)			(in thousands)			
Natural gas futures contracts	$(13,603)	$ 1,032	Fuel	$ (5,175)	$ 980	$ (15,081)	$ (130)
Purchased power	1,053	—	Purchased power	3,334	—	(2,068)	—
Total	$(12,550)	$ 1,032		$ (1,841)	$ 980	$ (17,149)	$ (130)

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

4. *Investments*

Investments were as follows as of September 30, 2019 and December 31, 2018:

Description	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
			(in thousands)		
September 30, 2019					
Nuclear decommissioning trust [1]					
Debt securities	$ 58,898	$ 4,764	$ —	$ 63,662	$ 63,662
Equity securities	84,610	52,971	(3,634)	133,947	133,947
Cash and other	466	—	—	466	466
Total Nuclear Decommissioning Trust	$ 143,974	$ 57,735	$ (3,634)	$ 198,075	$ 198,075
Unrestricted investments					
Government obligations	$ 5,354	$ 6	$ —	$ 5,360	$ 5,354
Total Unrestricted Investments	$ 5,354	$ 6	$ —	$ 5,360	$ 5,354
Other					
Equity securities	$ 89	$ 9	$ —	$ 98	$ 98
Non-marketable equity investments	2,118	2,240	—	4,358	2,118
Total Other	$ 2,207	$ 2,249	$ —	$ 4,456	$ 2,216
					$ 205,645
December 31, 2018					
Nuclear decommissioning trust [1]					
Debt securities	$ 56,055	$ 2,955	$ —	$ 59,010	$ 59,010
Equity securities	83,453	38,611	(7,264)	114,800	114,800
Cash and other	141	—	—	141	141
Total Nuclear Decommissioning Trust	$ 139,649	$ 41,566	$ (7,264)	$ 173,951	$ 173,951
Unrestricted investments					
Government obligations	$ 4,935	$ —	$ (5)	$ 4,930	$ 4,935
Debt securities	595	—	(2)	593	595
Total Unrestricted Investments	$ 5,530	$ —	$ (7)	$ 5,523	$ 5,530
Other					
Equity securities	$ 347	$ 46	$ —	$ 393	$ 393
Non-marketable equity investments	2,143	2,080	—	4,223	2,143
Total Other	$ 2,490	$ 2,126	$ —	$ 4,616	$ 2,536
					$ 182,017

[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 2018 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.

Contractual maturities of debt securities as of September 30, 2019, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Other [1]	$ —	$ —	$ 63,662	$ —	$ 63,662
Held to maturity	5,354	—	—	—	5,354
Total	$ 5,354	$ —	$ 63,662	$ —	$ 69,016

(1) The contractual maturities of other debt securities are measured using the effective duration of the bond fund within the nuclear decommissioning trust.

5. Other

Wildcat Point Generation Facility

We own Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility. Wildcat Point achieved commercial operation on April 17, 2018. The facility originally was scheduled to become operational in mid-2017. WOPC, a joint venture between PCL Industrial Construction Company and Sargent & Lundy, L.L.C., as the EPC contractor, claims the delay was associated with the incurrence of additional work and other matters, including alleged misrepresentation in the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. In 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. Venue was later transferred from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia. 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. We have offset the capitalized construction costs of Wildcat Point by $53.2 million of liquidated damages.

Additionally, in 2017, we filed a complaint in the United States District Court for the Eastern District of Virginia against WOPC, alleging that WOPC breached the EPC contract. Later that year, 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, be consolidated into one case. The trial date, originally scheduled for February 3, 2020, has been moved to May 4, 2020.

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.

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 1, 2024. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through March 1, 2024. As of September 30, 2019 and December 31, 2018, we had no borrowings and had a $0.5 million and $2.5 million letter of credit outstanding under this facility, respectively.

Cash and Cash Equivalents

For purposes of our Condensed Consolidated Statements of Cash Flows, we consider all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be 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 Sheets that sum to the total of the same amounts shown in the Condensed Consolidated Statements of Cash Flows:

	As of September 30,	
	2019	**2018**
	(in thousands)	
Cash and cash equivalents	$ 22,583	$ 71,447
Restricted cash and cash equivalents	24,130	14,200
Total	$ 46,713	$ 85,647

Restricted cash and cash equivalents relates to funds held in escrow for payments related to the construction of Wildcat Point.

Revenue Recognition

Our operating revenues are derived from sales to our members and non-members. We supply power requirements (energy and demand) to our eleven member distribution cooperatives subject to substantially identical wholesale power contracts with each of them. 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 sell excess purchased and generated energy to PJM, TEC, or third parties. Sales to TEC consist of sales of excess energy that we do not need to meet the actual needs of our member distribution cooperatives. TEC's sales to third parties are reflected as non-member revenues. For the three and nine months ended September 30, 2019 and 2018, we had no sales to TEC and TEC had no sales to third parties.

Our operating revenues for the three and nine months ended September 30, 2019 and 2018, were as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Member distribution cooperatives				
Sales to member distribution cooperatives, excluding renewable energy credit sales	$237,661	$230,408	$678,789	$657,521
Renewable energy credit sales to member distribution cooperatives	4	2	21	14
Total sales to member distribution cooperatives	$237,665	$230,410	$678,810	$657,535
Non-members				
Sales to non-members, excluding renewable energy credit sales	$ 11,812	$ 24,791	$ 25,011	$ 51,762
Renewable energy credit sales to non-members	3,252	2,385	4,672	2,950
Total sales to non-members	$ 15,064	$ 27,176	$ 29,683	$ 54,712
Total operating revenues	$252,729	$257,586	$708,493	$712,247

6. New Accounting Pronouncements

In February 2016, the FASB issued ASU 2016-02 Leases. 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 are required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. In July 2018, the FASB issued ASU 2018-11 Leases (Topic 842): Targeted Improvements, which provides an adoption method that would allow companies to apply the new guidance to the financial statements in the period of adoption and thereafter, and not apply the new guidance to comparative periods presented. Effective January 1, 2019, we elected the adoption method provided by ASU 2018-11 (Topic 842) and are not adjusting prior year comparative financial statements. We also elected the package of practical expedients under the transition guidance which permits us not to reassess under the new standard our prior conclusions for lease identification and lease classification on expired or existing contracts and whether initial direct costs previously capitalized would qualify for capitalization under ASU 2018-11 (Topic 842). Additionally, we elected the practical expedient related to land easements, allowing us to not reassess our current accounting treatment for existing agreements on land easements, which are not accounted for as leases. Upon adoption of the new lease standard, we recognized right-of-use assets and offsetting lease liabilities totaling approximately $0.1 million.

In June 2016, the FASB issued ASU 2016-13 Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses in Financial Instruments, and issued subsequent amendments to the initial guidance in November 2018 with ASU No. 2018-19, in April 2019 with ASU No. 2019-04, and in May 2019 with ASU No. 2019-05. The ASU amends the guidance on the impairment of financial instruments and adds an impairment model, known as the current expected credit loss ("CECL") model. The CECL model requires an entity to recognize its current estimate of all expected credit losses, rather than incurred losses, and applies to trade receivables and other receivables. The CECL model is designed to capture expected credit losses through the establishment of an allowance account, which will be presented as an offset to the amortized cost basis of the related financial asset. The new guidance is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and is applied using the modified-retrospective approach. We are currently evaluating the impact of this pronouncement. We plan to adopt this standard for the fiscal year beginning January 1, 2020.

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

Caution Regarding Forward-looking Statements

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

Critical Accounting Policies

As of September 30, 2019, there have been no significant changes in our critical accounting policies as disclosed in our 2018 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 nine months ended September 30, 2019, were primarily impacted by the operational availability and PJM's economic dispatch of our generating facilities, commercial operation of Wildcat Point, PJM charges for network transmission services, and the sale of Rock Springs and related assets.

- Generation from our owned facilities decreased 2.5%, as compared to the same period in 2018. Generation from Wildcat Point, which achieved commercial operation and was available for dispatch by PJM on April 17, 2018, increased 40.1%, whereas generation from Clover decreased 66.1% due to scheduled outages and PJM's economic dispatch of the facility, and generation from North Anna decreased 5.5% due to scheduled outages. Generation from our combustion turbine facilities decreased 14.7%, primarily due to the sale of Rock Springs and related assets on September 14, 2018.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased 20.3%. Purchased energy expense decreased 25.6% due to decreases in the volume, primarily due to generation from Wildcat Point, and the cost of purchased energy.

- Transmission expense increased 15.5% due to PJM charges for network transmission services.
- Operations and maintenance expense increased 23.6% due to expenditures incurred during scheduled outages of our generating facilities and costs associated with the long-term service agreement for Wildcat Point.
- Amortization of the gain on the sale of Rock Springs and related assets reduced our demand costs by $28.3 million.

As a result of these and other factors, demand revenues from our member distribution cooperatives increased $36.0 million, or 12.6%, and energy revenues from our member distribution cooperatives decreased $14.8 million, or 4.0%. Additionally, deferred energy expense changed by $35.9 million, from an $18.1 million under-collection in 2018 to a $17.9 million over-collection in 2019.

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 natural gas, nuclear, and coal 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, 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.

As detailed in the table below, we utilized Margin Stabilization to increase revenues for the three months ended September 30, 2019 and 2018, and to reduce revenues for the nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2019	**2018**	**2019**	**2018**
	(in thousands)			
Margin Stabilization adjustment	$ (110)	$ (3,130)	$ 5,413	$ 11,941

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 2018 Annual Report on Form 10-K.

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 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. Heating degree days are calculated as the number of degrees below 60 degrees in a single day. Cooling degree days are calculated as the number of degrees above 65 degrees in a single day. In a single calendar day, it is possible to have multiple heating degree and cooling degree days. The heating and cooling degree days for the three and nine months ended September 30, 2019 and 2018, were as follows:

	Three Months Ended September 30,			**Nine Months Ended September 30,**		
	2019	**2018**	**Change**	**2019**	**2018**	**Change**
Heating degree days	—	—	—%	2,016	1,993	1.2%
Cooling degree days	1,138	1,058	7.6	1,553	1,492	4.1

Power Supply Resources

We provide power to our members through a combination of our interests in Wildcat Point, a natural gas-fired combined cycle generation facility; North Anna, a nuclear power station; Clover, a coal-fired generation facility; two natural gas-fired combustion turbine facilities (Louisa and Marsh Run, and prior to September 14, 2018, Rock Springs); diesel-fired distributed generation facilities; and physically-delivered forward power purchase contracts and spot market energy purchases. Our energy supply resources for the three and nine months ended September 30, 2019 and 2018, were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2019		2018		2019		2018	
	(in MWh and percentages)							
Generated:								
Wildcat Point [1]	1,069,230	30.5%	1,331,437	36.1%	3,202,892	33.5%	2,286,185	21.9%
North Anna	424,494	12.1	480,845	13.1	1,281,276	13.4	1,356,366	13.0
Clover	274,847	7.8	482,001	13.1	422,084	4.4	1,244,644	11.9
Louisa	237,004	6.8	202,072	5.5	392,469	4.1	449,539	4.3
Marsh Run	317,257	9.0	159,608	4.3	614,806	6.5	518,867	5.0
Rock Springs [2]	—	—	125,414	3.4	—	—	212,957	2.0
Distributed Generation	1,324	—	802	—	2,086	—	1,410	—
Total Generated	2,324,156	66.2	2,782,179	75.5	5,915,613	61.9	6,069,968	58.1
Purchased:								
Other than renewable:								
Long-term and short-term	610,921	17.4	485,977	13.2	1,637,342	17.1	2,425,013	23.2
Spot market	454,739	13.0	286,016	7.7	1,464,187	15.3	1,381,633	13.3
Total Other than renewable	1,065,660	30.4	771,993	20.9	3,101,529	32.4	3,806,646	36.5
Renewable [3]	118,886	3.4	131,173	3.6	542,672	5.7	567,507	5.4
Total Purchased	1,184,546	33.8	903,166	24.5	3,644,201	38.1	4,374,153	41.9
Total Available Energy	3,508,702	100.0%	3,685,345	100.0%	9,559,814	100.0%	10,444,121	100.0%

(1) Wildcat Point achieved commercial operation on April 17, 2018.

(2) Rock Springs and related assets were sold on September 14, 2018.

(3) Related to our contracts from renewable facilities from which we obtain 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 operation of our generating facilities, which are under dispatch control of PJM. For further discussion of PJM, see “Business—Power Supply Resources—PJM” in Item 1 of our 2018 Annual Report on Form 10-K.

Operational Availability

The operational availability of our owned generating resources for the three and nine months ended September 30, 2019 and 2018, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Wildcat Point (1) (2)	84.2%	93.4%	85.6%	87.0%
North Anna (2)	87.5	99.4	88.4	93.2
Clover (2)	68.5	92.1	63.0	80.7
Louisa	94.7	100.0	94.3	96.8
Marsh Run	99.3	100.0	97.2	96.3
Rock Springs (3)	—	100.0	—	92.0

(1) Wildcat Point achieved commercial operation on April 17, 2018.

(2) Wildcat Point, North Anna, and Clover operational availabilities were impacted by scheduled outages in 2019.

(3) Rock Springs and related assets were sold on September 14, 2018.

Capacity Factor

The output of Wildcat Point, North Anna, and Clover, for the three and nine months ended September 30, 2019 and 2018, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Wildcat Point (1) (2)	50.1%	63.0%	51.4%	59.5%
North Anna (3)	87.6	99.2	89.1	94.4
Clover (2)	29.2	51.5	15.2	44.7

(1) Wildcat Point achieved commercial operation on April 17, 2018.

(2) Wildcat Point and Clover capacity factors were impacted by scheduled outages in 2019 and PJM's economic dispatch of the facilities.

(3) North Anna capacity factors were impacted by scheduled outages in 2019.

Sale of Rock Springs Combustion Turbine Facility

On September 14, 2018, we sold our interest in Rock Springs and related assets to EPRS for $115 million. Prior to the sale, we and EPRS had each individually owned two natural gas-fired combustion turbine units and a 50% undivided interest in related common facilities at Rock Springs. The transaction resulted in a gain of $42.7 million, which our board of directors approved to defer as a regulatory liability. We amortized $5.0 million of the gain in 2018 and the remaining $37.7 million is being amortized ratably in 2019.

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 power supply resources, 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 and nine months ended September 30, 2019 and 2018, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Revenues from sales to:				
Member distribution cooperatives				
Energy revenues	$ 128,422	$ 128,102	$ 357,573	$ 372,332
Demand revenues	109,243	102,308	321,237	285,203
Total revenues from sales to member distribution cooperatives	237,665	230,410	678,810	657,535
Non-members	15,064	27,176	29,683	54,712
Total operating revenues	$ 252,729	$ 257,586	$ 708,493	$ 712,247
Energy sales to:	(in MWh)			
Member distribution cooperatives	3,125,704	3,077,665	8,703,657	9,069,385
Non-members	367,463	580,761	802,902	1,324,291
Total energy sales	3,493,167	3,658,426	9,506,559	10,393,676
Average cost of energy to member distribution cooperatives (per MWh)	$ 41.09	$ 41.62	$ 41.08	$ 41.05
Average total cost to member distribution cooperatives (per MWh)	$ 76.04	$ 74.87	$ 77.99	$ 72.50

Sales of power and renewable energy credits by type of purchaser for the three and nine months ended September 30, 2019 and 2018, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Member distribution cooperatives				
Sales to member distribution cooperatives, excluding renewable energy credit sales	$ 237,661	$ 230,408	$ 678,789	$ 657,521
Renewable energy credit sales to member distribution cooperatives	4	2	21	14
Total sales to member distribution cooperatives	$ 237,665	$ 230,410	$ 678,810	$ 657,535
Non-members				
Sales to non-members, excluding renewable energy credit sales	$ 11,812	$ 24,791	$ 25,011	$ 51,762
Renewable energy credit sales to non-members	3,252	2,385	4,672	2,950
Total sales to non-members	$ 15,064	$ 27,176	$ 29,683	$ 54,712

Member Distribution Cooperatives

For the three and nine months ended September 30, 2019, total revenues from sales to our member distribution cooperatives were 3.1% and 3.2% higher, respectively, as compared to the same periods in 2018, due to increases in demand revenues, partially offset by the decrease in energy revenues for the nine months ended September 30, 2019.

Demand revenues increased $6.9 million, or 6.8%, for the three months ended September 30, 2019, primarily due to increases in capacity-related purchased power expense and operations and maintenance expense, partially offset by the amortization of the deferred gain on the sale of Rock Springs and related assets. Demand revenues increased $36.0 million, or 12.6%, for the nine months ended September 30, 2019, primarily due to increases in transmission expense, capacity-related purchased power expense, operations and maintenance expense, and interest charges, net; partially offset by the amortization of the deferred gain on the sale of Rock Springs and related assets. Energy revenues were relatively flat for the three months ended September 30, 2019, and decreased $14.8 million, or 4.0%, for the nine months ended September 30, 2019, due to the 4.0% decrease in energy sales in MWh to our member distribution cooperatives.

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, 2018	11.1
April 1, 2018	3.7
January 1, 2019	(1.3)

Non-members

For the three and nine months ended September 30, 2019, revenues from sales to non-members decreased $12.1 million and $25.0 million, respectively, as compared to the same periods in 2018.

Operating Expenses

The following is a summary of the components of our operating expenses for the three and nine months ended September 30, 2019 and 2018:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Fuel	$ 51,000	$ 65,134	$ 143,921	$ 147,573
Purchased power	83,851	71,059	238,828	299,645
Transmission	38,107	39,916	121,476	105,145
Deferred energy	15,403	17,482	17,855	(18,086)
Operations and maintenance	23,721	15,236	59,638	48,236
Administrative and general	11,358	11,593	38,395	34,848
Depreciation and amortization	17,207	17,057	51,539	45,818
Amortization of regulatory asset/(liability), net	(9,163)	(2,816)	(26,342)	(7,457)
Accretion of asset retirement obligations	1,386	1,330	4,154	3,991
Taxes, other than income taxes	2,350	2,597	7,185	7,315
Total Operating Expenses	$ 235,220	$ 238,588	$ 656,649	$ 667,028

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 $3.4 million, or 1.4%, and $10.4 million, or 1.6%, for the three and nine months ended September 30, 2019, respectively, as compared to the same periods in 2018. For the three and nine months ended

September 30, 2019, total operating expenses were principally impacted by changes in fuel, purchased power, transmission, deferred energy, operations and maintenance, and amortization of regulatory asset/(liability), net.

- Fuel expense decreased $14.1 million, or 21.7%, for the three months ended September 30, 2019, as compared to the same period in 2018, primarily as a result of the 16.5% decrease in generation from our owned facilities due to scheduled outages at Wildcat Point, North Anna, and Clover, PJM's economic dispatch of our generating facilities, and the sale of Rock Springs and related assets on September 14, 2018. Fuel expense decreased $3.7 million, or 2.5%, for the nine months ended September 30, 2019, as compared to the same period in 2018, primarily as a result of the 2.5% decrease in generation from our owned facilities.

- Purchased power expense, which includes the cost of purchased energy and capacity, increased $12.8 million, or 18.0%, for the three months ended September 30, 2019, as compared to the same period in 2018, due to the $7.3 million increase in capacity-related purchased power expense and the $5.5 million increase in purchased energy expense. The volume of purchased energy increased 31.2% as a result of decreased generation from our owned facilities, and was partially offset by the 17.6% decrease in the average cost of purchased energy. Purchased power expense decreased $60.8 million, or 20.3%, for the nine months ended September 30, 2019, as compared to the same period in 2018, due to the $72.8 million decrease in purchased energy expense, slightly offset by the $12.0 million increase in capacity-related purchased power expense. The volume of purchased energy decreased 16.7%, primarily due to generation from Wildcat Point, and the average cost of purchased energy decreased 10.7%.

- Transmission expense decreased $1.8 million, or 4.5%, and increased $16.3 million, or 15.5%, respectively, for the three and nine months ended September 30, 2019, as compared to the same periods in 2018, due to PJM charges for network transmission services.

- Deferred energy expense, which represents the difference between energy revenues and energy expenses, decreased $2.1 million for the three months ended September 30, 2019, and increased $35.9 million for the nine months ended September 30, 2019, as compared to the same periods in 2018. For the three months ended September 30, 2019 and 2018, we over-collected $15.4 million and $17.5 million, respectively. For the nine months ended September 30, 2019, we over-collected $17.9 million and for the nine months ended September 30, 2018, we under-collected $18.1 million. 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 2018 Annual Report on Form 10-K.

- Operations and maintenance expense increased $8.5 million, or 55.7%, and $11.4 million, or 23.6%, for the three and nine months ended September 30, 2019, as compared to the same periods in 2018, primarily due to costs related to scheduled outages at our owned facilities and costs associated with the long-term service agreement for Wildcat Point.

- Amortization of regulatory asset/(liability), net decreased $6.3 million and $18.9 million, respectively, for the three and nine months ended September 30, 2019, as compared to the same periods in 2018. For the three and nine months ended September 30, 2019, we amortized $9.4 million and $28.3 million, respectively, of the gain on the sale of Rock Springs and related assets. In 2018, we amortized $3.8 million and $11.3 million, respectively, of deferred revenue.

Other Items

Interest Charges, Net

The primary factors affecting our interest charges, net are issuance of indebtedness, scheduled payments of principal on our indebtedness, interest charges related to our revolving credit facility, and capitalized interest. The major components of interest charges, net for the three and nine months ended September 30, 2019 and 2018, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Interest on long-term debt	$ (15,032)	$ (15,553)	$ (45,083)	$ (46,656)
Interest on revolving credit facility	(255)	(693)	(607)	(1,948)
Other interest	(500)	(738)	(2,199)	(1,286)
Total interest charges	(15,787)	(16,984)	(47,889)	(49,890)
Allowance for borrowed funds used during construction	139	122	370	11,016
Interest charges, net	$ (15,648)	$ (16,862)	$ (47,519)	$ (38,874)

Interest charges, net increased $8.6 million for the nine months ended September 30, 2019, as compared to the same period in 2018, due to the decrease in allowance for borrowed funds used during construction (capitalized interest) related to the commencement of commercial operation of Wildcat Point.

Net Margin Attributable to ODEC

Net margin attributable to ODEC, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, was relatively flat for the three and nine months ended September 30, 2019, as compared to the same periods in 2018.

Financial Condition

The principal changes in our financial condition from December 31, 2018 to September 30, 2019, were caused by increases in our nuclear decommissioning trust, regulatory liabilities, accrued expenses, deferred charges–other, and deferred credits and other liabilities–other, and decreases in regulatory liability–deferral of gain on sale of asset and deferred energy.

- Nuclear decommissioning trust increased $24.1 million, primarily due to the increase in the market value of our investments.
- Regulatory liabilities increased $18.6 million, primarily due to the increase in the regulatory liability related to the unrealized gain on the North Anna nuclear decommissioning trust.
- Accrued expenses increased $17.3 million, due to accrued interest on long-term debt and accrued property taxes.
- Deferred charges–other increased $16.4 million, primarily due to additional collateral requirements related to our natural gas hedges.
- Deferred credits and other liabilities–other increased $12.8 million, primarily due to decreases in the fair value of our natural gas hedges.
- Regulatory liability–deferral of gain on sale of asset decreased $28.3 million due to the amortization of the gain on the sale of Rock Springs and related assets.
- Deferred energy decreased $17.9 million as a result of the over-collection of our energy costs in 2019. The deferred energy balance was an under-collection of $26.1 million and $8.2 million at December 31, 2018, and September 30, 2019, respectively.

Liquidity and Capital Resources

Sources

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

Operations

During the first nine months of 2019 and 2018, our operating activities provided cash flows of $56.6 million and $64.9 million, respectively. Operating activities in 2019 were primarily impacted by the $38.1 million change in regulatory assets and liabilities, the $18.1 million change in current liabilities, and the $17.9 million change in deferred energy.

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 1, 2024. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through March 1, 2024. As of September 30, 2019 and December 31, 2018, we had no borrowings and had a $0.5 million and $2.5 million letter of credit outstanding under this facility, 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 third quarter of 2019.

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

Recovery of Costs from PJM

In 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 facilities. In 2015, FERC denied our petition, we filed a request for rehearing, and FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. In 2016, FERC denied our request for rehearing and, on June 15, 2018, the United States Court of Appeals for the District of Columbia Circuit denied our petition for review. We are pursuing this matter in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. We have not recorded a receivable related to this matter.

Wildcat Point

On April 17, 2018, Wildcat Point achieved commercial operation and was available for dispatch by PJM. The facility originally was scheduled to become operational in mid-2017. WOPC, a joint venture between PCL Industrial Construction Company and Sargent & Lundy, L.L.C., as the EPC contractor, claims the delay was associated with the incurrence of additional work and other matters, including alleged misrepresentation in the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. In 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. Venue was later transferred from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia. 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, in 2017, we filed a complaint in the United States District Court for the Eastern District of Virginia against WOPC, alleging that WOPC breached the EPC contract. Later that year, 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, be consolidated into one case. The trial date, originally scheduled for February 3, 2020, has been moved to May 4, 2020.

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 the issues discussed above and certain other legal proceedings arising out of the ordinary course of business that 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 2018 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

Virginia CO_2 Regulation

On April 19, 2019, the VAPCB approved a regulation that would have reduced and limited CO_2 emissions from large (greater than 25 MW) electric power generating facilities by linking Virginia to the RGGI CO_2 cap and trade program. RGGI provides for a cap-and-trade program to regulate CO_2 emissions among participating northeastern and Mid-Atlantic States, including Delaware and Maryland. On May 2, 2019, Virginia Governor Ralph Northam signed the state budget, which includes a provision inserted by the legislature that prohibits Virginia from making expenditures related to RGGI. We believe this effectively bars Virginia from participating in RGGI without state legislative approval. The regulation passed by the VAPCB would have been effective beginning January 1, 2020; however, with the Governor's approval of the state budget, participation in RGGI by Virginia cannot occur until reconsideration by the Virginia legislature, which currently does not reconvene until January 2020. There is still considerable uncertainty as to the impact on ODEC's Virginia facilities. We will continue to follow the process closely.

For further discussion of the Virginia CO_2 Regulation, see "Regulation—Environmental—Virginia CO_2 Regulation" in Part I, Item 1 of our 2018 Annual Report on Form 10-K.

Affordable Clean Energy Rule ("ACE")

The Clean Power Plan, which took effect December 23, 2015, was stayed on February 9, 2016, by the courts. On October 16, 2017, the EPA proposed a rule to repeal the Clean Power Plan and on August 21, 2018, a replacement rule for the Clean Power Plan, ACE, was proposed. On September 6, 2019, ACE became effective and requires that each state implement plans to meet state-specific carbon emissions reductions no later than July 8, 2022. We have ownership interests in generating facilities in Virginia and Maryland and are exposed to the impact of inconsistent standards between states as well as the uncertainty of the implementation plans. We are closely monitoring the rulemaking related to ACE, and we currently cannot predict the impact of ACE on our existing facilities due to the uncertainties and complexities of the regulations and the unclear status of efforts to repeal the Clean Power Plan.

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: November 12, 2019

/s/ BRYAN S. ROGERS
Bryan S. Rogers
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: November 12, 2019

/s/ MARCUS M. HARRIS

Marcus M. Harris
President and Chief Executive Officer
(Principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Bryan S. Rogers, 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: November 12, 2019

/s/ BRYAN S. ROGERS

Bryan S. Rogers
Senior Vice President and Chief Financial Officer
(Principal financial officer)

Exhibit 32.1

OLD DOMINION ELECTRIC COOPERATIVE

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

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-Q for the period ending September 30, 2019 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: November 12, 2019

/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 September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Bryan S. Rogers, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 12, 2019

/s/ BRYAN S. ROGERS
Bryan S. Rogers
Senior Vice President and Chief Financial Officer
(Principal financial officer)