UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017

OR

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

For the transition period from to

Commission file number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE

(Exact name of Registrant as specified in its charter)

VIRGINIA **(State or other jurisdiction of incorporation or organization)**	**23-7048405** **(I.R.S. employer identification no.)**
4201 Dominion Boulevard, Glen Allen, Virginia **(Address of principal executive offices)**	**23060** **(Zip code)**

(804) 747-0592
(Registrant's telephone number, including area code)

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

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

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act? Yes ☐ No ☒

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act (the "Exchange Act"). Yes ☒ No ☐

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this form 10-K. ☒

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large 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 Exchange Act Rule 12b-2). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant. NONE

Indicate the number of shares outstanding of each of the Registrant's classes of common stock. The Registrant is a membership corporation and has no authorized or outstanding equity securities.

Documents incorporated by reference: NONE

OLD DOMINION ELECTRIC COOPERATIVE

2017 ANNUAL REPORT ON FORM 10-K

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SIGNATURES

GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-K 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
CAA	Clean Air Act
CCRs	Coal combustion residuals
CEC	Choptank Electric Cooperative, Inc.
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Clover	Clover Power Station
CO_2	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DEC	Delaware Electric Cooperative, Inc.
DPSC	Delaware Public Service Commission
DOE	U.S. Department of Energy
EGU	Electric generating unit
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005, as amended
EPC	Engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
GAAP	Accounting principles generally accepted in the United States
GHG	Greenhouse gases
Indenture	Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated January 1, 2011, of ODEC with Branch Banking and Trust Company, as trustee, as amended and supplemented
IRC	Internal Revenue Code of 1986, as amended
kV	Kilovolt
LIBOR	London Interbank Offered Rate
MATS	Mercury and Air Toxics Standards
Mitsubishi	Mitsubishi Hitachi Power Systems Americas, Inc.
Moody’s	Moody’s Investors Service
MPSC	Maryland Public Service Commission
MW	Megawatt(s)
MWh	Megawatt hour(s)
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
North Anna	North Anna Nuclear Power Station
North Anna Unit 3	A potential additional nuclear-powered generating unit at North Anna
NOVEC	Northern Virginia Electric Cooperative
NO_x	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NRECA	National Rural Electric Cooperative Association
NYMEX	New York Mercantile Exchange
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
PPA	Pension Protection Act
RCRA	Resource Conservation and Recovery Act, as amended
REC	Rappahannock Electric Cooperative

Abbreviation or Acronym	Definition
RICE	Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model
RPS	Renewable portfolio standards
RTO	Regional transmission organization
RUS	U.S. Department of Agriculture Rural Utilities Service
S&P	Standard & Poor's Ratings Services
SEPA	Southeastern Power Administration
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SVEC	Shenandoah Valley Electric Cooperative
TEC	TEC Trading, Inc.
VDEQ	Virginia Department of Environmental Quality
Virginia Power	Virginia Electric and Power Company
VMDAEC	Virginia, Maryland, and Delaware Association of Electric Cooperatives
VSCC	Virginia State Corporation Commission
Wildcat Point	Wildcat Point Generation Facility
WOPC	White Oak Power Constructors
XBRL	Extensible Business Reporting Language

PART I

ITEM 1. BUSINESS

OVERVIEW

Old Dominion Electric Cooperative was incorporated under the laws of the Commonwealth of Virginia in 1948 as a not-for-profit power supply cooperative. We are organized for the purpose of supplying the power our member distribution cooperatives require to serve their customers on a cost-effective basis. We serve their power requirements pursuant to long-term, all-requirements wholesale power contracts. Through our member distribution cooperatives, we served approximately 580,000 retail electric customers (meters), representing a total population of approximately 1.4 million people in 2017.

We supply our member distribution cooperatives' power requirements, consisting of demand requirements and energy requirements, through a portfolio of resources including generating facilities, power purchase contracts, and spot market energy purchases. Our generating facilities are fueled by a mix of coal, nuclear, natural gas, and fuel oil. We are a member of a regional transmission organization, PJM, and we participate in its energy, capacity, and transmission services markets to serve our member distribution cooperatives. See "Power Supply Resources" below and "Properties" in Item 2 for a description of these resources.

We are owned entirely by our members, which are the primary purchasers of the power we sell. We have two classes of members. Our Class A members are customer-owned electric distribution cooperatives that are engaged in the retail sale of power to their customers. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our member distribution cooperatives primarily serve rural, suburban, and recreational areas of the mid-Atlantic region. See "Members—Service Territories and Customers" below.

We are a power supply cooperative. In general, a cooperative is a business organization owned by its members, which are also either the cooperative's wholesale or retail customers. Cooperatives are designed to give their members the opportunity to satisfy their collective needs in a particular area of business more effectively than if the members acted independently. As not-for-profit organizations, cooperatives are intended to provide services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Margins not distributed to members constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors of the cooperative deems it appropriate to do so.

Electric distribution cooperatives form power supply cooperatives to acquire power supply resources, typically through the construction of generating facilities or the development of other power purchase arrangements, at a lower cost than if they were acquiring those resources alone.

Our Class A members are electric distribution cooperatives. Electric distribution cooperatives own and operate electric distribution systems to supply the power requirements of their retail customers. Electric distribution cooperatives own and maintain nearly half of the distribution lines in the United States and serve almost three-quarters of the United States' land mass.

We are a not-for-profit electric cooperative and currently are exempt from federal income taxation under IRC Section 501(c)(12).

We are not a party to any collective bargaining agreement. We had 136 employees as of March 1, 2018.

Our principal executive office is located at 4201 Dominion Boulevard, Glen Allen, Virginia 23060. Our telephone number is (804) 747-0592.

MEMBERS

Member Distribution Cooperatives

General

Our member distribution cooperatives provide electric services, consisting of power supply, transmission services, and distribution services (including metering and billing services) to residential, commercial, and industrial customers. We have eleven member distribution cooperatives that serve customers in 70 counties in Virginia, Delaware, and Maryland. The member distribution cooperatives' distribution business involves the operation of substations, transformers, and electric lines that deliver power to their customers.

Eight of our member distribution cooperatives provide electric services on the Virginia mainland:

BARC Electric Cooperative
Community Electric Cooperative
Mecklenburg Electric Cooperative
Northern Neck Electric Cooperative
Prince George Electric Cooperative
Rappahannock Electric Cooperative
Shenandoah Valley Electric Cooperative
Southside Electric Cooperative

Three of our member distribution cooperatives provide electric services on the Delmarva Peninsula:

A&N Electric Cooperative in Virginia
Choptank Electric Cooperative, Inc. in Maryland
Delaware Electric Cooperative, Inc. in Delaware

The member distribution cooperatives are not our subsidiaries, but rather our owners. We have no interest in their assets, liabilities, equity, revenues, or margins.

Revenues from our member distribution cooperatives and the percentage each contributed to total revenues from sales to our member distribution cooperatives in 2017 are as follows:

Member Distribution Cooperatives	Revenues	
	(in millions)	
Rappahannock Electric Cooperative	$ 217.7	29.8%
Shenandoah Valley Electric Cooperative	146.8	20.0
Delaware Electric Cooperative, Inc.	97.5	13.3
Choptank Electric Cooperative, Inc.	69.7	9.5
Southside Electric Cooperative	58.4	8.0
A&N Electric Cooperative	46.0	6.3
Mecklenburg Electric Cooperative	36.7	5.0
Prince George Electric Cooperative	20.6	2.8
Northern Neck Electric Cooperative	18.2	2.5
Community Electric Cooperative	11.4	1.6
BARC Electric Cooperative	8.6	1.2
Total	$ 731.6	100.0%

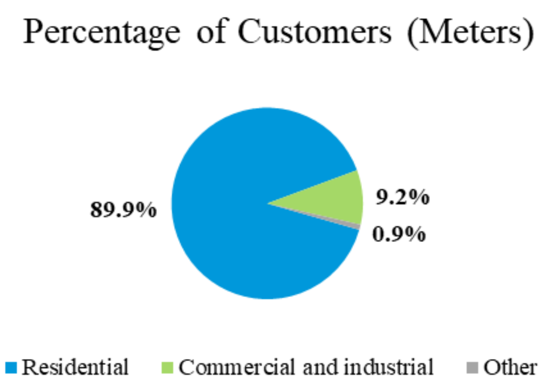
In 2017, there was no individual customer of our member distribution cooperatives that constituted 1% or more of our revenues from our member distribution cooperatives.

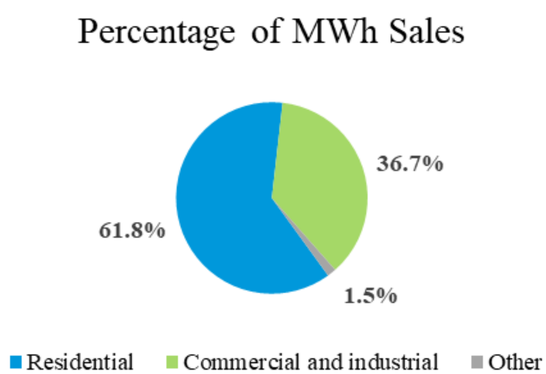
Service Territories and Customers

The territories served by our member distribution cooperatives cover large portions of Virginia, Delaware, and Maryland. These service territories range from the extended suburbs of Washington, D.C. to the North Carolina border and from the Atlantic shores of Virginia, Delaware, and Maryland to the Appalachian Mountains.

Our member distribution cooperatives' service territories encompass primarily rural, suburban, and recreational areas. Our member distribution cooperatives' customers' requirements for capacity and energy generally are seasonal and increase in winter and summer as home heating and cooling needs increase and then decline in the spring and fall as the weather becomes milder. Our member distribution cooperatives also serve major industries which include manufacturing, poultry, telecommunications, agriculture, forestry and wood products, health care, and recreation.

Our member distribution cooperatives' sales of energy in 2017 totaled approximately 11,600,000 MWh. These sales were divided by customer class as follows:





From 2012 through 2017, our eleven member distribution cooperatives experienced a compound annual growth rate of 0.9% in the number of customers (meters) and energy sales measured in MWh were relatively flat.

Our eleven member distribution cooperatives' average number of customers per mile of energized line has been relatively unchanged from 2012 to 2017 at approximately 9.5 customers per mile. System densities of our member distribution cooperatives in 2017 ranged from 6.3 customers per mile in the service territory of BARC Electric Cooperative to 14.4 customers per mile in the service territory of A&N Electric Cooperative. In 2017, the average service density for all electric distribution cooperatives in the United States was approximately 7.4 customers per mile.

Delaware and Maryland each currently grant all retail customers the right to choose their power supplier. Virginia currently grants a limited number of large retail customers the right to choose their power suppliers and then only in very limited circumstances. The laws of each state grant utilities, including our member distribution cooperatives, the exclusive right to provide transmission and distribution (including metering and billing) services and to be the default providers of power to their customers in service territories certified by their respective state public service commissions. See "Regulation of Member Distribution Cooperatives" and "Competition" below.

Wholesale Power Contracts

Our financial relationships with our member distribution cooperatives are based primarily on our contractual arrangements for the supply of power and related transmission and ancillary services. These arrangements are set forth in our wholesale power contracts with our member distribution cooperatives which are effective until January 1, 2054, and beyond this date unless either party gives the other at least three years notice of termination. The wholesale power contracts are all-requirements contracts. Each contract obligates us to sell and deliver to our member distribution cooperative, and obligates our member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so.

An exception to the all-requirements obligations of our member distribution cooperatives relates to the ability of our eight mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from SEPA, a federal power marketing administration. Purchases under this exception constituted less than 2% of our member distribution cooperatives' total energy requirements in 2017.

There are two additional limited exceptions to the all-requirements nature of the contract. One exception 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. The other exception permits our member distribution cooperatives to purchase additional power from other suppliers in limited circumstances following approval by our board of directors.

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 will be 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.

As of December 31, 2017, none of our member distribution cooperatives had utilized the other exception noted above.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formula rate. We review our formula rate design at least every three years to consider whether it is appropriately achieving its intended results. The formula rate, which has been filed with and accepted by FERC, is designed to recover our total cost of service and create a firm equity base. See “Regulation—Rate Regulation” below, "Legal Proceedings—FERC Proceeding Related to Formula Rate" in Item 3, and “Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate” in Item 7.

More specifically, the formula rate is intended to meet all of our costs, expenses, and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement, and decommissioning of our generating plants, transmission system, or related facilities, services provided to the member distribution cooperatives, and the acquisition and transmission of power or related services, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);
- any additional cost or expense, imposed or permitted by any regulatory agency; and
- additional amounts necessary to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory, and governmental requirements, which apply to us from time to time.

Regulation of Member Distribution Cooperatives

Of our 11 member distribution cooperatives, eight currently participate in RUS loan or guarantee programs. These member distribution cooperatives have entered into loan documents with RUS that we understand contain affirmative and negative covenants, including with respect to matters such as accounting, issuances of securities, rates and charges for the sale of power, construction or acquisition of facilities, and the purchase and sale of power. In addition, we understand financial covenants in these member distribution cooperatives' loan documents require them to design rates to achieve an interest coverage ratio and a debt service coverage ratio. Finally, we understand that the principal loan documentation of our member distribution cooperatives that do not participate in RUS loan or guarantee programs contains similar covenants.

Our member distribution cooperatives in Virginia are subject to rate regulation by the VSCC in the provision of electric services to their customers, but they have the ability to pass through changes in their wholesale power costs, including the demand and energy costs we charge our member distribution cooperatives, to their customers. Our Virginia member distribution cooperatives also may adjust their rates for distribution service by a maximum net increase or decrease of 5%, on a cumulative basis, in any three-year period without approval by the VSCC. Additionally, they may make adjustments to their rates to collect fixed costs through a new or modified fixed monthly charge rather than through volumetric charges associated with energy usage, so long as such adjustments are revenue neutral.

The MPSC regulates the rates and services offered by our Maryland member distribution cooperative, CEC, other than wholesale power costs, which are a pass-through to CEC's customers. Our Delaware member distribution cooperative, DEC, is not regulated by the DPSC, including with respect to wholesale power costs which are a pass-through to its customers.

We are not subject to any RPS; however DEC is subject to RPS. DEC meets the RPS through purchases of renewable energy credits, and owned and purchased resources pursuant to the 5% or 5 MW exception in its wholesale power contract with us. See "Wholesale Power Contracts" above.

Competition

Delaware and Maryland each have laws unbundling the power component (also known as the generation component) of electric service to retail customers, while maintaining regulation of transmission and distribution services. All retail customers in Delaware, including customers of DEC, are currently permitted to purchase power from a registered supplier only after DEC approves the supplier's ability to do business in its service territory. All retail customers in Maryland, including customers of CEC, are currently permitted to purchase power from the registered supplier of their choice. As of March 1, 2018, no retail customer of DEC or CEC has switched to an alternative power supplier.

In Virginia, retail choice in the selection of a power supplier is available to customers that consume at least 5 MW of power individually or in the aggregate (with aggregation subject to the approval of the VSCC) and that do not account for more than 1% of the incumbent utility's peak load during the past year. Currently, no customer of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Beginning June 1, 2016, Bear Island, an industrial customer of REC and the only customer of any of our member distribution cooperatives that has noncoincident peak demand that exceeds 90 MW, elected to purchase its power requirements from an alternate supplier. Additionally, all Virginia retail customers are permitted to select an alternative power supplier that provides 100% renewable energy if their incumbent utility, such as one of our member distribution cooperatives, does not offer this same option. As of December 31, 2017, eight of our nine Virginia member distribution cooperatives provided this option.

Currently, we do not anticipate that any of these limited rights to retail choice of our member distribution cooperatives' customers, individually or in the aggregate, will have a material impact on our financial condition, results of operations, or cash flows.

TEC

TEC is owned by our member distribution cooperatives and currently is our only Class B member. We have a power sales contract with TEC under which we may sell to TEC power that we do not need to meet the needs of our member distribution cooperatives. TEC then sells this power to the market under market-based rate authority granted by FERC. Additionally, we have a separate contract under which we may purchase natural gas from TEC. TEC does not engage in speculative trading. To facilitate TEC's participation in the power and natural gas markets, we have agreed to provide a maximum of $200 million in credit support to TEC. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Uses—Significant Contingent Obligations—TEC Guarantees" in Item 7.

POWER SUPPLY RESOURCES

General

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 natural gas-fired 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 past three years were as follows:

	Year Ended December 31,					
	2017		2016		2015	
	(in MWh and percentages)					
Generated:						
Clover	1,616,377	13.6%	2,714,966	21.3%	2,734,519	19.6%
North Anna	1,870,626	15.7	1,766,491	13.9	1,887,395	13.5
Louisa	262,797	2.2	366,274	2.9	403,489	2.9
Marsh Run	472,447	4.0	553,597	4.3	689,713	4.9
Rock Springs	143,571	1.2	362,738	2.8	297,610	2.1
Distributed Generation	605	—	1,066	—	1,388	—
Total Generated	4,366,423	36.7	5,765,132	45.2	6,014,114	43.0
Purchased:						
Other than renewable:						
Long-term and short-term	4,913,333	41.3	5,211,045	40.9	6,554,835	46.8
Spot market	1,849,489	15.5	993,413	7.8	677,836	4.8
Total Other than renewable	6,762,822	56.8	6,204,458	48.7	7,232,671	51.6
Renewable (1)	777,505	6.5	782,871	6.1	751,458	5.4
Total Purchased	7,540,327	63.3	6,987,329	54.8	7,984,129	57.0
Total Available Energy	11,906,750	100.0%	12,752,461	100.0%	13,998,243	100.0%

(1) 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.

In 2017, our generating facilities satisfied approximately 73.4% of our PJM capacity obligation. For a description of our generating facilities, see "Properties" in Item 2. In 2017, we obtained the remainder of our PJM capacity obligation through the PJM RPM capacity auction process and purchased capacity contracts. See "PJM" below. The energy requirements not met by our owned generating facilities were obtained from multiple suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. See "Power Purchase Contracts" below.

In 2017, our peak demand obligation to our member distribution cooperatives occurred in January and was 2,911 MW.

We plan to continue purchasing energy into the future by utilizing a combination of physically-delivered forward power purchase contracts, as well as spot market purchases. As we have done in the past, we expect to adjust our portfolio of power supply resources to reflect our projected power requirements and changes in the market. To assist us in these efforts, we engage ACES, an energy trading and risk management company. Specifically, ACES assists us in negotiating power purchase contracts, evaluating the credit risk of counterparties, modeling our power requirements, bidding and dispatch of the generating facilities that we operate, and executing and settling energy transactions. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Power Supply Planning

By utilizing various long-term and short-term planning processes and models, we continually evaluate power supply options available to us to meet the needs of our member distribution cooperatives. We have policies that establish targets that define how our projected power needs will be met, and one of the ways we manage these targets is the utilization of hedging. We use hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. These hedging instruments have varying time periods ranging from one month to multiple years in advance. Additionally, we evaluate other power supply options including the acquisition, development, or disposition of generating facilities.

Wildcat Point

We are the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. Wildcat Point's major equipment consists of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. While the facility was scheduled to become operational in mid-2017, we currently anticipate that Wildcat Point will achieve substantial completion in the spring of 2018. The majority of construction has been completed; however some additional construction work and testing is required before Wildcat Point becomes commercially operable and available for dispatch by PJM to meet a portion of our member distribution cooperatives' power requirements. WOPC, the EPC contractor, claims that 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. See "Item 3 – Legal Proceedings."

PJM

PJM is an RTO that coordinates the transmission of wholesale electricity in all or parts of 13 states and the District of Columbia. As a federally regulated RTO, PJM must act independently and impartially in managing the regional transmission system and the wholesale electricity market. PJM is primarily responsible for ensuring the reliability of the largest centrally dispatched energy market in North America. PJM coordinates the continuous buying, selling, and delivery of wholesale electricity throughout its members' service territories. PJM system operators continuously conduct dispatch operations and monitor the status of the transmission grid of its participants. PJM also oversees a regional planning process for transmission expansion to ensure the continued reliability of the PJM electric system. PJM coordinates and establishes policies for the generation, purchase, and sale of capacity and energy in the control areas of its members.

All of our member distribution cooperatives' service territories are in PJM. As a member of PJM, we are subject to the operations of PJM, and our generating facilities are under dispatch control of PJM. We transmit power to our member distribution cooperatives through the transmission facilities subject to operational control of PJM. We have agreements with PJM that provide us with access to transmission facilities under PJM's operational control as necessary to deliver energy to our member distribution cooperatives. We own a limited amount of transmission facilities. See "Properties—Transmission" in Item 2.

PJM balances its participants' power requirements with the power resources available to supply those requirements. Based on this evaluation of supply and demand, PJM schedules and dispatches available generating facilities throughout its region in a manner intended to meet the demand for energy in the most reliable and cost-effective manner. Thus PJM directs the dispatch of these facilities even though it does not own them. When PJM cannot dispatch the most economical generating facilities due to transmission constraints, PJM will dispatch more expensive generating facilities to meet the required power requirements. PJM participants whose power requirements cause the redispatch are obligated to pay the additional costs to dispatch the more expensive generating facilities. These additional costs are commonly referred to as congestion costs. PJM conducts the auction of financial transmission rights for future periods to provide market participants an opportunity to hedge these congestion costs.

The PJM energy market consists of day-ahead and real-time markets. PJM's day-ahead market is a forward market in which hourly locational marginal prices are calculated for the following day based on the prices at which the owners of generating facilities, including ODEC, offer to run their facilities to meet the requirements of energy customers. PJM's real-time market is a spot market in which current locational marginal prices are calculated at five-minute intervals.

PJM rules require that load serving entities, such as ODEC, meet certain minimum capacity obligations. These obligations can be met through a combination of owned generation resources and purchases under bilateral agreements and from forward capacity auctions under PJM's capacity construct, known as RPM. The purpose of PJM's capacity construct is to develop a longer-term pricing program for capacity resources, to provide localized pricing for capacity, and to reduce the resulting investment risk to owners of generating resources, thus encouraging new investment in generating facilities. The value of capacity resources can vary by location and RPM provides for the recognition of the locational value. To date, PJM has conducted capacity auctions for capacity to be supplied through May 31, 2021. Each annual auction is held 36 months before each subsequent delivery year, and incremental auctions may be held at prescribed dates after the base residual auction for each delivery year to adjust for changes to the load forecast and the availability of capacity.

Concurrent with the PJM delivery year beginning June 1, 2016, the PJM tariff provides for a new component referred to as capacity performance, which is intended to improve the reliability of the power grid by increasing the availability of generating units, especially during emergency conditions. Generation owners, such as ODEC, could earn increased compensation for capacity for some of their generating units and will be exposed to significantly higher charges if their generation units do not perform during emergency conditions. For the PJM delivery year beginning June 1, 2016, qualifying generating units were allowed to be voluntarily offered into PJM's capacity auction as a capacity performance unit. A unit not offered as a capacity performance unit, known as a base capacity unit, will be excluded from the assessment of the charges for non-performance during the winter months. Starting with the delivery year beginning June 1, 2020, PJM will require the majority of generating resources to be offered as capacity performance units, eliminating the base capacity option. We continue to evaluate our bidding strategy for our generating units for the PJM capacity auctions.

Power Purchase Contracts

We purchase significant amounts of power in the market from investor-owned utilities and power marketers through long-term and short-term physically-delivered forward power purchase contracts. We also purchase power in the spot energy market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. See "Risk Factors" in Item 1A. below. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy and sales of excess energy. Additionally, we utilize policies, procedures, and various hedging instruments to manage our power market risks. These policies and procedures, developed in consultation with ACES, are designed to strike an appropriate balance between minimizing costs and reducing energy cost volatility. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Renewables

We have contracts with companies that own and operate wind, solar, and landfill gas facilities. These contracts allow us to buy output, including renewable energy credits, from the renewable facilities at a predetermined price. We sell these renewable energy credits to our member distribution cooperatives and non-members. We do not own or operate any of these facilities and are not responsible for their operational costs or performance.

Fuel Supply

Coal

Virginia Power, as operating agent of Clover, has the sole authority and responsibility to procure coal for the facility. Virginia Power advises us that it uses both long-term contracts and short-term spot agreements to acquire the low sulfur bituminous coal used to fuel the facility. We are not a direct party to any of these procurement contracts and we do not control their terms or duration. As of December 31, 2017 and December 31, 2016, there was a 55-day and a 61-day supply of coal at Clover, respectively. We anticipate that sufficient supplies of coal will be available in the future to operate the facility when dispatched by PJM. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Nuclear

Virginia Power, as operating agent of North Anna, has the sole authority and responsibility to procure nuclear fuel for the facility. Virginia Power advises us that it primarily uses long-term contracts to support North Anna's nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices, which are dependent upon the market environment. We are not a direct party to any of these procurement contracts and we do not control their terms or duration. Virginia Power advises us that current agreements, inventories, and spot market availability are expected to support North Anna's current and planned fuel supply needs for the near term and that additional fuel is purchased as required to attempt to ensure optimal cost and inventory levels.

Under the Nuclear Waste Policy Act of 1982, the DOE is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as North Anna, in accordance with contracts executed with the DOE. The DOE did not begin accepting spent fuel in 1998 as specified in its contract. As a result, Virginia Power sought reimbursement for certain spent nuclear fuel-related costs incurred and in 2012 signed a settlement agreement with the DOE. See Note 1 of the Notes to Consolidated Financial Statements in Item 8.

Natural Gas

Our three combustion turbine facilities and Wildcat Point are fueled by natural gas and are located adjacent to natural gas transmission pipelines. We are responsible for procuring the natural gas to be used by all of our units at these facilities and have developed and utilize a natural gas supply strategy for providing natural gas. The strategy includes securing transportation contracts and incorporating the ability to use No. 2 distillate fuel oil as a backup fuel for Louisa and Marsh Run, as needed, to minimize natural gas pipeline transportation costs. We have identified our primary natural gas suppliers and have negotiated the contracts needed for procurement of physical natural gas. We have put in place strategies and mechanisms to financially hedge our natural gas needs. We anticipate that sufficient supplies of natural gas will be available in the future to support the operation of our combustion turbine facilities and Wildcat Point, but significant price volatility may occur. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

REGULATION

General

We are subject to regulation by FERC and, to a limited extent, state public service commissions. Some of our operations also are subject to regulation by the VDEQ, the Maryland Department of the Environment, the DOE, the NRC, and other federal, state, and local authorities. Compliance with future laws or regulations may increase our operating and capital costs by requiring, among other things, changes in the design or operation of our generating facilities.

Rate Regulation

We establish our rates for power furnished to our member distribution cooperatives pursuant to our formula rate, which has been accepted by FERC. The VSCC, the DPSC, and the MPSC do not have jurisdiction over our rates, charges, and services.

Our formula rate is intended to permit us to collect revenues, which, together with revenues from all other sources, are equal to all of our costs and expenses, plus a targeted amount equal to 20% of our total interest charges, plus additional equity contributions as approved by our board of directors. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate" in Item 7. Our current formula rate was accepted by FERC and became effective January 1, 2014, subject to refund, pending a final order from FERC. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Item 3.

FERC may review our rates upon its own initiative or upon complaint and order a reduction of any rates determined to be unjust, unreasonable, or otherwise unlawful and order a refund for amounts collected during such proceedings in excess of the just, reasonable, and lawful rates.

Our charges to TEC are established under our market-based sales tariff filed with FERC.

Other Regulation

In addition to its jurisdiction over rates, FERC also regulates the issuance of securities and assumption of liabilities by us, as well as mergers, consolidations, the acquisition of securities of other utilities, and the disposition of property under FERC jurisdiction. Under FERC regulations, we are prohibited from selling, leasing, or otherwise disposing of the whole of our facilities subject to FERC jurisdiction, or any part of such facilities having a value in excess of $10 million without FERC approval. We are also required to seek FERC approval prior to merging or consolidating our facilities with those of any other entity having a value in excess of $10 million.

The VSCC, the DPSC, and the MPSC oversee the siting of our utility facilities in their respective jurisdictions.

Environmental

We are subject to federal, state, and local laws and regulations, and permits designed to both protect human health and the environment and to regulate the emission, discharge, or release of pollutants into the environment. We believe that we are in material compliance with all current requirements of such environmental laws and regulations and permits. However, as with all electric utilities, the operation of our generating units could be affected by future changes in environmental laws or new environmental regulations. We continue to monitor activity related to changes in environmental laws and regulations, including new requirements. Capital expenditures and increased operating costs required to comply with any future regulations could be significant. See "Risk Factors" in Item 1A. Our capital expenditures for environmental improvements at our generating facilities were approximately $3.8 million and $6.0 million in 2017 and 2016, respectively.

Clean Air Act ("CAA")

Currently, the most significant environmental law affecting our operations is the CAA. The CAA requires, among other things, that owners and operators of fossil fuel-fired power stations limit emissions of SO_2, particulate matter, mercury, and NO_x. Additionally, regulatory programs are in place for new units and are being proposed for existing units to limit emissions of CO_2 and other GHG. Discussed below are certain standards and regulations under the CAA that impact us.

- Cross-State Air Pollution Rule
- Acid Rain Program
- Mercury and Air Toxics Standards
- National Ambient Air Quality Standards
- CO_2 New Source Performance Standards for EGUs
- Clean Power Plan
- Greenhouse Gas Prevention of Significant Deterioration Permitting

Cross-State Air Pollution Rule ("CSAPR")

CSAPR requires 27 states and the District of Columbia to significantly improve air quality by reducing power plant SO_2 and NO_x emissions that contribute to ozone and fine particle pollution in other states. Phase 2 emissions budgets were applicable beginning in 2017. Based upon published allocations/new source set-aside allowances for Virginia and Maryland, we anticipate that we will have to purchase a large number of NO_x and a limited number of SO_2 CSAPR allowances for Clover. We anticipate that we will have to purchase the majority of emissions allowances required for Wildcat Point and will apply for new source set-aside NO_X allowances from Maryland. Wildcat Point will need to purchase allowances for any emissions that exceed the number of new source set-aside allowances received. Currently, there is an adequate supply of NO_x allowances available for purchase for Wildcat Point. The number of set-aside allowances available for Wildcat Point will depend on the number of new sources requesting the allowances. Because the CSAPR allowance market is relatively new, we cannot predict the potential financial impacts of such purchases.

Acid Rain Program

Under the CAA's Acid Rain Program, each of our fossil fuel-fired plants must have SO_2 allowances equal to the number of tons of SO_2 they emit into the atmosphere annually. The total number of SO_2 allowances for all facilities is capped, and individual allowances are issued to facilities on the basis of past utilization and other factors. SO_2 allowances issued to individual sources can be traded. As a facility that was built before the Acid Rain Program, Clover receives an annual allocation of SO_2 allowances at no cost based upon its baseline operations. Our newer facilities, Louisa, Marsh Run, Rock Springs, and Wildcat Point, need to obtain allowances under the Acid Rain Program. Because they are primarily gas-fired generating facilities, the number of SO_2 allowances these newer facilities must obtain is typically minimal and can be supplied from any excess SO_2 allowances allocated to Clover.

Mercury and Air Toxics Standards ("MATS")

MATS regulates mercury, acid gases, and other air toxic organic compounds from coal and oil-fired power plants. Coal and oil-fired power plants were required to meet maximum achievable control technology standards to control the pollutants regulated by MATS by April 16, 2015. Clover has demonstrated compliance with this rule and continues to submit periodic reports. We do not anticipate that any additional emissions control measures will be required to continue to comply with MATS due to the existing pollution control equipment, which removes greater than 90% of the mercury emitted from the facility.

National Ambient Air Quality Standards ("NAAQS")

As part of the NAAQS, states will be required to develop and implement plans to address sources emitting pollutants which contribute to the formation of ozone. In November 2016, the EPA published the proposed designations and SIP requirements for implementation. We anticipate that the EPA will finalize designations of the ozone NAAQS in the future. Compliance requirements are dependent upon the attainment designation and we currently anticipate that compliance may begin in 2020 and go through 2027. We currently do not anticipate any emissions control requirement changes for our existing facilities. The EPA is still developing the implementation guidance related to the NAAQS. We will continue to follow this rulemaking in order to determine potential impacts related to our facilities.

CO_2 New Source Performance Standards for EGUs

In 2015, the EPA finalized the national standards for CO_2 emissions from new fossil fuel-fired electric generating units under 111(b) of the CAA. The standards limit CO_2 emissions from new fossil fuel-fired electric generating units, newly constructed and reconstructed fossil fuel-fired stationary combustion turbines, and baseload natural gas-fired units. This rule would affect permitting and operational requirements applicable to new, fossil fuel-fired facilities. We do not currently know the cost of compliance or the extent of control requirements that might be applicable to any future facilities.

CO_2 Emissions Guidelines for Existing EGUs ("Clean Power Plan")

In 2015, the EPA issued final emission guidelines for CO_2 from existing electric utility generating units under 111(d) of the CAA. The final regulations, referred to as the Clean Power Plan, took effect December 23, 2015. The final rule established rate-based and mass-based goals for each state, with interim goals during years 2022 to 2029, and final goals for target year 2030. The primary legal challenge to the Clean Power Plan is pending in the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court granted a stay of the implementation of the Clean Power Plan, pending resolution of the challenge pending before the D.C. Circuit, including any review of that court's decision by the Supreme Court.

On October 16, 2017, the EPA proposed a rule to repeal the Clean Power Plan. The comment period related to this proposal extends to April 26, 2018, and a number of hearings are scheduled across the country. We are monitoring the rulemaking, and are utilizing stakeholder processes to provide comments. We currently cannot predict the impact of the Clean Power Plan on our existing facilities due to the uncertainties and complexities of the regulations and the unclear status of efforts to repeal the plan.

Greenhouse Gas Prevention of Significant Deterioration Permitting

In 2010, the EPA issued the Tailoring Rule to address GHG emissions from stationary sources under the CAA permitting programs. The final rule set thresholds for GHG emissions that define when permits under the New Source Review Prevention of Significant Deterioration and Title V Operating Permit programs are required for new and existing industrial facilities. In late 2010, the EPA issued a series of rules that provide the necessary regulatory framework for permitting of both new and existing large stationary sources. Regulation of GHG emissions may affect the future renewal of Title V Operating Permits for Clover, Louisa, Marsh Run, and Rock Springs, as the rules will require that existing facilities quantify their GHGs emissions and may establish limits in their reissued operating permits.

Regional Greenhouse Gas Initiative ("RGGI")

RGGI provides for a cap-and-trade program to regulate CO_2 emissions among participating northeastern and Mid-Atlantic States, including Delaware and Maryland. We are required to purchase RGGI CO_2 allowances for each ton of CO_2 emitted by our Rock Springs units and Wildcat Point. We anticipate that Wildcat Point will apply for and be awarded a portion of the allowances from the Maryland clean generation set-aside account through the year 2022. We continue to project that there will be an adequate quantity of CO_2 allowances available for purchase to support both Rock Springs and Wildcat Point.

Virginia CO_2 Regulation

The governor of the Commonwealth of Virginia issued an executive directive on May 16, 2017, directing VDEQ to develop a proposed regulation by the end of 2017 to abate, control, or limit CO_2 emissions from electric power facilities. The proposed rule was presented to the Virginia Air Pollution Control Board for approval and was subsequently published in the Virginia Register of Regulations on January 8, 2018, with a 90-day public comment period. The major implementation component of the regulation is the linkage to RGGI. There is considerable uncertainty as to the impact on ODEC's Virginia facilities given (1) the proposed consignment auction approach has never been used before under the RGGI model, (2) all other participating RGGI states have deregulated electric markets, and (3) the stringency of the Virginia budget cap in relation to the overall RGGI cap. We will be providing significant comment on this proposed rule and will be following the process closely.

Clean Water Act

The Clean Water Act and applicable state laws regulate water intake structures, discharges of cooling water, storm water runoff, and other wastewater discharges at our generating facilities. Our permits are subject to periodic review and renewal proceedings, and can be made more restrictive over time. Limitations on the thermal discharges in cooling water, or withdrawal of cooling water during low flow conditions, can restrict our operations. In 2013, the EPA proposed revising limits on certain toxic pollutants that would require most steam electric (including coal and combined cycle, natural gas) facilities to strengthen existing, or implement new, controls to manage water discharges from their sites. The final rule was published in the Federal Register on November 3, 2015, with an implementation date of January 4, 2016. The final rule, known as the Steam Electric Effluent Limitation Guidelines revised the guidelines to set the first limits on the levels of toxic metals in wastewater that can be discharged from power plants. The final rule sets new or additional requirements for wastewater streams from flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

On December 5, 2016, several industry parties represented by the Utility Water Act Group filed opening briefs against the final rule. The briefs alleged several instances where it is believed that the EPA violated standards and procedures in producing the guidelines. On September 13, 2017, a final rule was issued postponing compliance dates for "best available technology economically achievable" effluent limitations and pretreatment standards for two waste streams of existing sources, bottom ash transport water and flue-gas desulfurization wastewater, for a period of two years. In the interim EPA is working to revise the 2015 ruling after further input from stakeholders.

We do not currently expect there to be a significant impact on facility operations. We are currently in compliance and will continue to follow this rulemaking in order to determine potential future impacts related to our facilities.

Resource Conservation and Recovery Act, as amended ("RCRA")

The EPA regulates CCRs under the RCRA to address the risks from disposal of CCRs generated by coal combustion at electric generating facilities. In 2014, the EPA proposed regulations governing the "Disposal of Coal Combustion Residuals for Electric Utilities," which addressed risks related to coal ash disposal, such as leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. The final rule was published in 2015, and established technical requirements for CCR landfills and surface impoundments, and for monitoring and cleanup of affected soil or groundwater. Virginia Power, as operator of Clover, is currently making modifications to Clover to comply with RCRA. Also, under the final rule, facilities are subject to recordkeeping requirements, requirements to notify the state, and a requirement to develop and maintain a publicly available internet site containing information on its actions to comply with the elements of the final rule.

On September 14, 2017, the EPA announced that it had granted two petitions to reconsider substantive provisions of the final rule. The EPA has yet to announce any rulings related to its reconsideration of the final rule. We continue to monitor these regulations and the potential impact on the operations at Clover.

Future Regulation

New legislative and regulatory proposals are frequently introduced on both the federal level and state level that would modify the environmental regulatory programs applicable to our facilities. Changing regulatory requirements can increase our capital and operating costs and adversely affect the ability to operate our existing facilities, as well as restrict construction of new facilities.

ITEM 1A. – RISK FACTORS

RISK FACTORS

The following risk factors and all other information contained in this report should be considered carefully when evaluating ODEC. These risk factors could affect our actual results and cause these results to differ materially from those expressed in any forward-looking statements of ODEC. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. We consider the risks listed below to be material, but you may view risks differently than we do and we may omit a risk that we consider immaterial but you consider important. An adverse outcome of any of the following risks could materially affect our business or financial condition. These risk factors should be read in conjunction with the other detailed information set forth elsewhere in this report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, including "Caution Regarding Forward-looking Statements," and the notes to Consolidated Financial Statements.

Changes in fuel and purchased power costs could increase our operating costs.

We are subject to changes in fuel costs, which could increase the cost of generating power and purchased power costs. Increases in fuel costs and purchased power costs increase the cost to our member distribution cooperatives. The market prices for fuel may fluctuate over relatively short periods of time. Factors that could influence fuel and purchased power costs are:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- constraints related to the transportation of fuels;
- price competition among fuels used to produce electricity, including natural gas, coal, and oil;
- energy transmission capacity constraints;
- the impact of implementation of new technologies in the power industry, such as batteries;

- federal, state, and local energy and environmental regulation and legislation, including increased regulation of the extraction of natural gas and coal; and
- natural disasters, war, terrorism, and other catastrophic events.

We rely substantially on purchases of energy from other power suppliers which exposes us to market price risk.

We supply our member distribution cooperatives with all of their power (energy and demand) requirements, with limited exceptions. Our costs to provide this energy and demand are passed through to our member distribution cooperatives under our wholesale power contracts. We obtain the power to serve their requirements from generating facilities in which we have an interest and purchases of power from other power suppliers.

Historically, our power supply strategy has relied substantially on purchases of energy from other power suppliers. In 2017, we purchased approximately 63.3% of our energy resources. These purchases consisted of a combination of purchases under physically-delivered forward contracts and purchases of energy in the spot market. Our reliance on purchases of energy from other suppliers will continue into the future. Our reliance on energy purchases could also increase because the operation of our generating facilities is subject to many risks, including changes in their dispatch, shutdown, or breakdown or failure of equipment.

Purchasing power helps us mitigate high fixed costs related to the ownership of generating facilities but exposes us to significant market price risk because energy prices can fluctuate substantially. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we utilize our judgment and assumptions in our models. These judgments and assumptions relate to factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas, used to generate electricity. Our models cannot predict what will actually occur and our results may vary from what our models predict, which may in turn impact our resulting costs to our members. Our models become less reliable the further into the future that the estimates are made. Although we have developed strategies to attempt to meet our power requirements in an economical manner and we have implemented a hedging strategy to limit our exposure to variability in the market, we still may purchase energy at a price which is higher than other utilities' costs of generating energy or future market prices of energy. For further discussion of our market price risk, see "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Environmental regulation may limit our operations or increase our costs or both.

We are required to comply with numerous federal, state, and local laws and regulations, relating to the protection of the environment. We believe that we have obtained all material environmental approvals currently required to own and operate our existing facilities or that necessary approvals have been applied for and will be issued in a timely manner. We may incur significant additional costs because of compliance with these requirements. Failure to comply with environmental laws and regulations could have a material effect on us, including potential civil or criminal liability and the imposition of fines or expenditures of funds to bring our facilities into compliance. Delay in obtaining, or failure to obtain and maintain in effect, any environmental approvals, or the delay or failure to satisfy any applicable environmental regulatory requirements related to the operation of our existing facilities or the sale of energy from these facilities could result in significant additional cost to us.

The Clean Power Plan, which took effect December 23, 2015, was stayed on February 9, 2016, by the courts and on October 16, 2017, the EPA proposed a rule to repeal the Clean Power Plan. If implemented, the Clean Power Plan requires that each state implement plans to meet state-specific carbon emissions reductions. 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 the Clean Power Plan. We currently cannot predict the impact of the Clean Power Plan on our existing facilities due to the uncertainties and complexities of the regulations and the unclear status of efforts to repeal the plan.

The governor of the Commonwealth of Virginia issued an executive directive on May 16, 2017, directing VDEQ to develop a proposed regulation by the end of 2017 to abate, control, or limit CO_2 emissions from electric power facilities. The proposed rule was presented to the Virginia Air Pollution Control Board for approval and was subsequently published in the Virginia Register of Regulations on January 8, 2018, with a 90-day public comment period. The major implementation component of the regulation is the linkage to RGGI. We have ownership interests in generating facilities in Virginia and could be potentially exposed to higher costs to dispatch these facilities under the proposed rule.

We cannot predict the cost or the effect of any future environmental legislation or regulation. New environmental laws or regulations, the revision or reinterpretation of existing environmental laws or regulations, or penalties imposed for non-compliance with existing environmental laws or regulations may require us to incur additional expenses and could have a material adverse effect on the cost of power we supply our member distribution cooperatives. See "Regulation—Environmental" in Item 1.

Our financial condition is largely dependent upon our member distribution cooperatives.

Our financial condition is largely dependent upon our member distribution cooperatives satisfying their obligations to us under the wholesale power contract that each has executed with us. The wholesale power contracts require our member distribution cooperatives to pay us for power furnished to them in accordance with our FERC formula rate. Our board of directors, which is composed of representatives of our members, can approve changes in the rates we charge to our member distribution cooperatives without seeking FERC approval, with limited exceptions. In 2017, 63.1% of our revenues from sales to our member distribution cooperatives were received from our three largest members, REC, SVEC, and DEC.

Our member distribution cooperatives' ability to collect their costs from their members may have an impact on our financial condition. Economic conditions may make it difficult for some customers of our member distribution cooperatives to pay their power bills in a timely manner, which could ultimately affect the timeliness of our member distribution cooperatives' payments to us.

Technological advancements and other changes impacting power requirements of our member distribution cooperatives' customers may reduce demand for power from us.

Technological advancements are occurring in the electric industry, including advancements related to self-generation and distributed energy technologies. Distributed energy technologies include fuel cells, batteries, micro turbines, wind turbines and solar cells. The increased adoption of these technologies and a greater degree of the adoption of energy efficiency technology and conservation by our member distribution cooperatives' customers, along with the impact of regional economic conditions, could reduce our member distribution cooperatives' demand for power from us and cause our long-term load expectations to be materially different than planned.

We are subject to risks associated with owning an interest in a nuclear generating facility.

We have an 11.6% undivided ownership interest in North Anna, which provided approximately 15.7% of our energy requirements in 2017. Ownership of an interest in a nuclear generating facility involves risks, including:

- potential liabilities relating to harmful effects on the environment and human health resulting from the operation of the facility and the storage, handling, and disposal of radioactive materials;
- significant capital expenditures relating to maintenance, operation, and repair of the facility, including repairs required by the NRC;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with operation of the facility; and
- uncertainties regarding the technological and financial aspects of decommissioning a nuclear plant at the end of its licensed life.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of North Anna. If the facility is not in compliance, the NRC may impose fines or shut down the units until compliance is achieved, or both depending upon its assessment of the situation. Revised safety requirements issued by the

NRC have, in the past, necessitated substantial capital expenditures at other nuclear generating facilities. North Anna's operating and safety procedures may be subject to additional federal or state regulatory scrutiny as a result of worldwide events related to nuclear facilities. In addition, if a serious nuclear incident at North Anna did occur, it could have a material but presently indeterminable adverse effect on our operations or financial condition. Further, any unexpected shut down at North Anna as a result of regulatory non-compliance or unexpected maintenance will require us to purchase replacement energy.

We may not complete generating facility construction projects that we commence, or we may complete such projects on materially different terms or timing than initially anticipated and we may not be able to achieve the intended benefits of any such projects, if completed.

Construction projects, such as investments in generation assets, carry with them the risk that decisions made today can have implications well into the future. Failure to anticipate market, technology, and regulatory risks regarding particular capital assets can impact their cost to operate and value in the future. We anticipate that we will need to seek additional financing in the future to fund these construction and expansion projects and we may not be able to secure such financing on favorable terms. Construction carries with it risks relating to timely completion and operational effectiveness. We may not be able to complete the construction or expansion projects on time or at all as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, other construction delays, difficulties with partners, contractors, or suppliers, or other factors beyond our control. Even if the construction and expansion projects are completed, the total costs of the construction and expansion projects may be higher than anticipated and the performance of our business following the construction and expansion projects may not meet expectations. Further, we may not be able to timely and effectively integrate the construction and expansion projects into our operations, or the integration may result in unforeseen operating difficulties or unanticipated costs. Any of these or other factors could adversely affect our ability to realize the anticipated benefits from construction and expansion projects.

We may have operational deficiencies or catastrophic events related to our generating facilities.

The operation of our generation or transmission facilities involves risks, including the breakdown or failure of power generation equipment, transmission lines, pipes or other equipment or processes, fuel supply delivery, and performance below expected levels of output or efficiency. The occurrence of any of these events could result in:

- substantial charges assessed by PJM as a result of the expectation that generation facilities would be available if called upon to be dispatched;
- significant additional capital expenditures to repair or replace the affected facilities; or
- the purchase of potentially more costly replacement power on the open market.

Counterparties under power purchase and natural gas arrangements may fail to perform their obligations to us.

Because we rely substantially on the purchase of energy and natural gas from other suppliers, we are exposed to the risk that counterparties will default in performance of their obligations to us. On an on-going basis we analyze and monitor the default risks of counterparties and other credit issues related to these purchases, and we may require our counterparties to post collateral with us; however, defaults may still occur. Defaults may take the form of failure to physically deliver the purchased energy or natural gas. If a default occurs, we may be forced to enter into alternative contractual arrangements or purchase energy or natural gas in the forward or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

The use of hedging instruments could impact our liquidity.

We use various hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. These hedging instruments generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties when a counterparty's credit exposure to us is in excess of agreed upon credit limits. When commodity prices decrease to levels below the levels where we have hedged future costs, we may be required to use a material portion of our cash or liquidity facilities to cover these collateral requirements.

Additionally, existing or new regulations related to the use of hedging instruments may impact our access to and use of hedging instruments.

Adverse changes in our credit ratings may require us to provide credit support for some of our obligations and could negatively impact our liquidity and our ability to access capital.

S&P, Moody's, and Fitch currently rate our outstanding obligations issued under our Indenture at "A+," "A2," and "A," respectively. Additionally, we have an issuer credit rating of "A+" from S&P, and an implied senior unsecured rating of "A" from Fitch. If these agencies were to downgrade our ratings, particularly below investment grade, we may be required to deposit funds or post letters of credit related to our power purchase arrangements, which may reduce our available liquidity and impact our access to future liquidity resources. To the extent that we would have to provide additional credit support as a result of a downgrade in our credit ratings, our ability to access additional credit may be limited and our liquidity may be materially impaired. Also, we may be required to pay higher interest rates on our revolving credit facility and financings that we may need to undertake in the future, and our potential pool of investors and funding sources could decrease.

War, acts and threats of terrorism, sabotage, cyber security breach, natural disaster, and other significant events could adversely affect our operations.

We cannot predict the impact that any future terrorist attack, sabotage, cyber security breach, or natural disaster may have on the energy industry in general, or on our business in particular. Infrastructure facilities, such as electric generation, transmission, and distribution facilities, and RTOs, could be direct targets of, or indirect casualties of, an act of terror, sabotage, or cyber security breach. The physical or cyber security compromise of our facilities could adversely affect our ability to operate or manage our facilities effectively. Additionally, any military strikes or sustained military campaign may affect the operation of our facilities in unpredictable ways, such as changes in financial markets, and disruptions of fuel supplies and energy markets. We also use third-party vendors to electronically process certain of our business transactions. Information systems, both ours and those of third-party information processors, are vulnerable to cyber security breach. Cyber security incidents could impact the ability to operate our generation and transmission assets, delay the development and construction of new facilities or capital improvement projects to existing facilities, and result in unauthorized disclosure of personal information regarding employees and their dependents, contractors, and other individuals. Instability in financial markets as a result of terrorism, war, sabotage, cyber security breach, natural disasters, pandemic, credit crises, recession, or other factors could have a significant negative effect on the U.S. economy, and in the increased cost of financing and insurance coverage, which could negatively impact our results of operations and financial condition.

Failure to comply with regulatory reliability standards, and other regulatory requirements could subject us to substantial monetary penalties.

As a result of EPACT, owners, operators, and users of bulk electric systems, including ODEC, are subject to mandatory reliability standards enacted by NERC and its regional entities, and enforced by FERC. We must follow these standards, which are in place to require that proper functions are performed to ensure the reliability of the bulk power system. Although the standards are developed by the NERC Standards Committee, which includes representatives of various electric energy sectors, and must be just and reasonable, the standards are legally binding and compliance may require increased capital expenditures and costs to provide electricity to our member distribution cooperatives under our wholesale power contracts. If we are found to be in non-compliance with any mandatory reliability standards we could be subject to sanctions, including potentially substantial monetary penalties. New, revised or reinterpreted laws or regulations related to reliability standards and/or participation in wholesale power markets could also result in substantial monetary penalties if ODEC is found to have violated or failed to comply with applicable standards, laws and regulations.

Poor market performance will affect the asset values in our nuclear decommissioning trust and our defined benefit retirement plans, which may increase our costs.

We are required to maintain a funded trust to satisfy our future obligation to decommission North Anna. A decline in the market value of those assets due to poor investment performance or other factors may increase our funding requirements for these obligations which may increase our costs.

We participate in the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan. The cost of these plans is funded by our payments to NRECA. Poor performance of investments in these benefit plans may increase our costs to make up our allocable portion of any underfunding.

Potential changes in accounting practices may adversely affect our financial results.

We cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry, or our operations specifically. New accounting standards could be issued that could change the way we record revenues, expenses, assets, and liabilities. These changes in accounting standards could adversely affect our reported earnings or could increase reported liabilities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our principal properties consist of our interest in six electric generating facilities, additional distributed generation facilities across our member distribution cooperatives' service territories, and a limited amount of transmission facilities. Substantially all of our physical properties are subject to the lien of our Indenture. Our generating facilities consist of the following:

Generating Facility	Ownership Interest	Location	Primary Fuel	Commercial Operation Date	Net Capacity Entitlement [1]
Clover	50%	Halifax County, Virginia	Coal	Unit 1 – 10/1995	220 MW
				Unit 2 – 03/1996	218 MW
					438 MW
North Anna	11.6%	Louisa County, Virginia	Nuclear	Unit 1 – 06/1978 [2]	110 MW
				Unit 2 – 12/1980 [2]	110 MW
					220 MW
Louisa	100%	Louisa County, Virginia	Natural Gas [3]	Unit 1 – 06/2003	84 MW
				Unit 2 – 06/2003	84 MW
				Unit 3 – 06/2003	84 MW
				Unit 4 – 06/2003	84 MW
				Unit 5 – 06/2003	168 MW
					504 MW
Marsh Run	100%	Fauquier County, Virginia	Natural Gas [3]	Unit 1 – 09/2004	168 MW
				Unit 2 – 09/2004	168 MW
				Unit 3 – 09/2004	168 MW
					504 MW
Rock Springs	50% [4]	Cecil County, Maryland	Natural Gas	Unit 1 – 06/2003	168 MW
				Unit 2 – 06/2003	168 MW
					336 MW
Distributed Generation	100%	Multiple	Diesel	07/2002	20 MW
				05/2016	6 MW
					26 MW
Wildcat Point	100%	Cecil County, Maryland	Natural Gas	Under construction	940 MW
				Total	2,968 MW

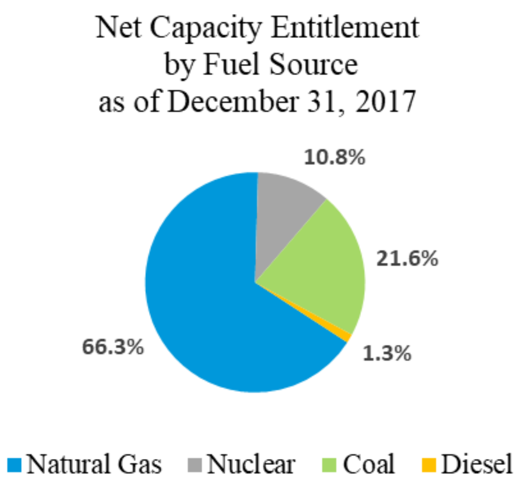
(1) Represents an approximation of our entitlement to the maximum dependable capacity in summer conditions for Clover and North Anna, which does not represent actual usage. Represents a nominal average of summer and winter capacities for Louisa, Marsh Run, and Rock Springs. For Wildcat Point, represents the projected maximum dependable capacity in summer conditions.

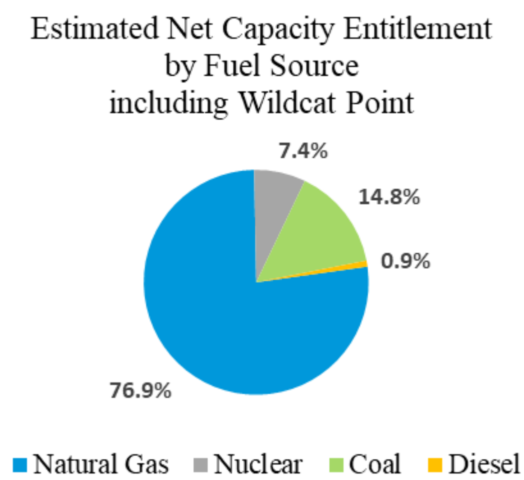
(2) We purchased our 11.6% undivided ownership interest in North Anna in December 1983.

(3) The units at this facility also operate on No. 2 distillate fuel oil as an alternate fuel source.

(4) We own 100% of two units, each with a net capacity rating of 168 MW, and 50% of the common facilities for the facility. See "Combustion Turbine Facilities—Rock Springs" below.

Generating Facilities by Primary Fuel





Clover

Virginia Power, the co-owner of Clover, is responsible for operating, and procuring and arranging for the transportation of the fuel required to operate Clover. See "Business—Power Supply Resources—Fuel Supply—Coal" in Item 1. ODEC and Virginia Power are each entitled to half of the power generated by Clover. We are responsible for and must fund half of all additions and operating costs associated with Clover, as well as half of Virginia Power's administrative and general expenses directly attributable to Clover.

North Anna

The NRC has granted operating licenses for North Anna Unit 1 and Unit 2 that extend through April 1, 2038, and August 21, 2040, respectively. Virginia Power, the co-owner of North Anna, has announced its intention to apply for a 20-year operating license extension for North Anna. Virginia Power is responsible for operating and procuring nuclear fuel for North Anna. See "Business—Power Supply Resources—Fuel Supply—Nuclear" in Item 1. We are entitled to 11.6% of the power generated by North Anna. We are responsible for and must fund 11.6% of all post-acquisition date additions and operating costs associated with North Anna, as well as a pro-rata portion of Virginia Power's administrative and general expenses directly attributable to North Anna. In addition, we separately fund our pro-rata portion of the decommissioning costs of North Anna. ODEC and Virginia Power also bear pro-rata any liability arising from ownership of North Anna, except for liabilities resulting from the gross negligence of the other.

Combustion Turbine Facilities

Louisa

We are responsible for the operation and maintenance of Louisa and we supply all services, goods, and materials required to operate and maintain the facility, including arranging for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Marsh Run

We are also responsible for the operation and maintenance of Marsh Run and we supply all services, goods, and materials required to operate and maintain the facility, including arranging for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Rock Springs

ODEC and Essential Power Rock Springs, LLC each individually own two units (a total of 336 MWs each) and 50% of the common facilities at Rock Springs. Additionally, ODEC and Essential Power Rock Springs, LLC each individually bid its respective units into PJM as determined to be necessary and prudent. We arrange for the transportation and supply of the natural gas required by the operator for our units at Rock Springs.

Rock Springs is currently operated and maintained by Essential Power Operating Services, LLC, an affiliate of Essential Power Rock Springs, LLC, pursuant to a service agreement under which Essential Power Operating Services, LLC supplies all services, goods, and materials, other than natural gas, required to operate the facility. We are responsible for all costs associated with the development, construction, additions, and operating costs and administrative and general expenses relating to our two units and the proportional share of the costs relating to the common facilities for Rock Springs.

Distributed Generation Facilities

We have six distributed generation facilities in our member distribution cooperatives' service territories primarily to enhance our system's reliability. We have 14 MW and 12 MW of distributed generation to serve our member distribution cooperatives in the Virginia mainland territory and the Delmarva Peninsula territory, respectively.

Wildcat Point

We are the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. See "Power Supply Resources—Wildcat Point" in Item 1.

Transmission

We own approximately 110 miles of transmission lines on the Virginia portion of the Delmarva Peninsula. We also own two 1,100-foot, 500 kV transmission lines and a 500 kV substation at Rock Springs jointly with Essential Power Rock Springs, LLC. As a transmission owner in PJM, we have relinquished dispatch control of these transmission facilities to PJM and contracted with third parties to operate and maintain them.

Indenture

The Indenture grants a lien on substantially all of our real property and tangible personal property and some of our intangible personal property in favor of the trustee, with limited exceptions. The obligations outstanding under the Indenture, including all of our long-term indebtedness, are secured equally and ratably by the trust estate under the Indenture.

ITEM 3. LEGAL PROCEEDINGS

FERC Proceeding Related to Formula Rate

On September 30, 2013, we filed with FERC to revise our cost-based formula rate in order to more closely align our cost recovery from our member distribution cooperatives with the methodologies used by PJM to allocate costs to us. On November 8, 2013, Bear Island, a customer of REC, filed a motion to intervene, protest, and request for hearing. On December 2, 2013, FERC issued its order accepting the proposed revisions for filing to become effective January 1, 2014, subject to refund, and establishing hearing and settlement procedures. On April 13, 2015, we received an initial decision from the hearing judge. On January 19, 2017, FERC issued its order on the hearing judge's initial decision. On February 21, 2017, we submitted our compliance filing, revising the formula rate as directed in the order. Additionally, on February 21, 2017, Bear Island filed a request for rehearing. On March 22, 2017, FERC issued an order granting rehearing of its initial order for the limited purpose of FERC's further consideration of the matter. Our formula rate remains in effect subject to refund pending a final order from FERC. If a refund is ultimately determined, we believe it will result in a reallocation of costs among our member distribution cooperatives.

Recovery of Costs from PJM

On June 23, 2014, we filed a petition at FERC seeking recovery from PJM of approximately $14.9 million of unreimbursed costs, which were incurred during the first quarter of 2014 related to the dispatch of our combustion turbine generating facilities. On June 9, 2015, FERC denied our petition, on July 9, 2015, we filed a request for rehearing, and on August 10, 2015, FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. On March 1, 2016, FERC denied our request for rehearing and on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit, and on October 24, 2017, the court heard oral arguments. 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

Wildcat Point was scheduled to become operational in mid-2017; however, we currently anticipate that it will achieve substantial completion in the spring of 2018. WOPC, the EPC contractor, claims that the delay is associated with the incurrence of additional work and other matters, including alleged misrepresentation under the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. On May 24, 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. An amended complaint was filed on July 21, 2017. On August 21, 2017, motions were filed by Alstom and us to transfer venue from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia, and on November 7, 2017, these motions were granted. We have reviewed the asserted claims of WOPC against us and believe they are without merit. We do not believe any liability is estimable or probable and intend to vigorously defend against these claims.

Additionally, on September 29, 2017, we filed a complaint in the 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

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 4. MINE SAFETY DISCLOSURES

Not Applicable

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Not Applicable

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data below present selected historical information relating to our financial condition and results of operations. The financial data for the five years ended December 31, 2017, is derived from our audited consolidated financial statements. You should read the information contained in this table together with our consolidated financial statements, the related notes to the consolidated financial statements, and the discussion of this information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except ratios)				
Statement of Operations Data					
Operating Revenues	$ 753,107	$ 877,871	$ 1,020,028	$ 951,576	$ 842,069
Operating Margin	39,974	45,192	48,953	50,525	52,590
Net Margin attributable to ODEC	26,627	17,637	11,879	9,100	9,573
Margins for Interest Ratio	2.13	1.67	1.27	1.21	1.21

	December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except ratios)				
Balance Sheet Data					
Net Electric Plant	$1,703,291	$1,650,918	$1,457,573	$1,097,669	$ 965,378
Total Investments	297,502	270,268	254,624	252,062	255,984
Other Assets	208,369	208,930	289,402	283,470	303,260
Total Assets	$2,209,162	$2,130,116	$2,001,599	$1,633,201	$1,524,622
Patronage capital (1)	$ 415,384	$ 402,857	$ 390,976	$ 379,097	$ 369,997
Non-controlling interest	5,744	5,725	5,704	5,687	5,691
Long-term debt (2)	1,198,396	990,083	1,017,926	715,497	743,355
Revolving credit facility	43,400	152,000	—	86,000	—
Long-term debt due within one year	40,792	28,292	28,292	28,292	28,292
Total Capitalization and Short-term Debt	$1,703,716	$1,578,957	$1,442,898	$1,214,573	$1,147,335
Equity Ratio (3)	24.5%	25.6%	27.2%	31.4%	32.4%

(1) For 2017, patronage capital includes a $14.1 million equity contribution and a $14.1 million patronage capital retirement. For 2016, patronage capital includes a $5.8 million equity contribution and a $5.8 million patronage capital retirement.

(2) Includes debt issuance costs as a direct reduction to long-term debt.

(3) Equity ratio equals patronage capital divided by the sum of our long-term debt, revolving credit facility, long-term debt due within one year, and patronage capital.

Our Indenture obligates us to establish and collect rates for service to our member distribution cooperatives, which are reasonably expected to yield a margin for interest ratio for each fiscal year equal to at least 1.10, subject to any necessary regulatory or judicial approvals. The Indenture requires that these amounts, together with other moneys available to us, provide us moneys sufficient to remain in compliance with our obligations under the Indenture. We calculate the margins for interest ratio by dividing our margins for interest by our interest charges.

Margins for interest under the Indenture equal:

- our net margins;
- plus revenues that are subject to refund at a later date, which were deducted in the determination of net margins;
- plus non-recurring charges that may have been deducted in determining net margins;
- plus total interest charges (calculated as described below);
- plus income tax accruals imposed on income after deduction of total interest for the applicable period.

In calculating margins for interest under the Indenture, we factor in any item of net margin, loss, income, gain, earnings or profits of any of our affiliates or subsidiaries, only if we have received those amounts as a dividend or other distribution from the affiliate or subsidiary or if we have made a contribution to, or payment under a guarantee or like agreement for an obligation of, the affiliate or subsidiary. Any amounts that we are required to refund in subsequent years do not reduce margins for interest as calculated under the Indenture for the year the refund is paid.

Interest charges under the Indenture equal our total interest charges (other than capitalized interest) related to (1) all obligations under the Indenture, (2) indebtedness secured by a lien equal or prior to the lien of the Indenture, and (3) obligations secured by liens created or assumed in connection with a tax-exempt financing for the acquisition or construction of property used by us, in each case including amortization of debt discount and expense or premium.

On November 7, 2017, our board of directors declared a patronage capital retirement of $14.1 million, to be paid on April 2, 2018. On December 13, 2016, our board of directors declared a patronage capital retirement of $5.8 million, to be paid on April 3, 2017.

ITEM 7. 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.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of ODEC and TEC. See "Note 1—Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements" in Item 8.

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 energy purchases. We also supply the transmission services necessary to deliver this power to our member distribution cooperatives.

Our results for the year ended December 31, 2017, were primarily impacted by decreases in our total energy rate, changes in our member distribution cooperatives' requirements for power, the dispatch of our generating facilities, our continued investment in Wildcat Point, decreased transmission expenses, revenue deferral, an additional equity contribution, declaration of a patronage capital retirement, and the return of North Anna Unit 3 development costs.

- In 2016 and 2017, we implemented decreases to our total energy rate that resulted in the 13.3% decrease in the average cost of energy we charged to our member distribution cooperatives and also contributed to the $43.7 million under-collection of energy costs, which resulted in the change to our deferred energy balance from $40.0 million over-collected to $3.7 million under-collected.
- Our energy sales in MWh to our member distribution cooperatives were 4.5% lower primarily due to decreases in our load requirements related to retail choice in Virginia and a limited exception provision in our wholesale power contract. Additionally, we experienced milder weather during 2017.
- Clover generation decreased 40.5% due to PJM's economic dispatch of the facility and reduced operational availability. Our combustion turbine facilities generation decreased 31.5% due to PJM's economic dispatch of the facilities. These factors contributed to the $43.8 million, or 31.6%, decrease in fuel expense.
- We continued with the construction of Wildcat Point. Through December 31, 2017, we capitalized construction costs related to Wildcat Point totaling $789.7 million, including $77.8 million of capitalized interest, offset by $53.2 million of liquidated damages.
- Transmission expense decreased $24.2 million, or 19.9%, primarily due to decreases in PJM charges for network transmission services.

- On November 7, 2017, our board of directors approved the establishment of a regulatory liability to defer revenue of $15.0 million, to be amortized in 2018.
- 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.
- On June 1, 2017, Virginia Power agreed to return the remaining balance of North Anna Unit 3 development costs that we incurred prior to our 2011 decision not to participate in North Anna Unit 3. In the second quarter of 2017, we recorded $11.3 million, comprised of $6.9 million of amortization of regulatory asset/liability, net, and $4.4 million of interest income on North Anna Unit 3 cost recovery. During the second quarter of 2017, we received a payment of $6.8 million and established a receivable for the remaining balance.

Wildcat Point

We are the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. Wildcat Point's major equipment consists of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. While the facility was scheduled to become operational in mid-2017, we currently anticipate that Wildcat Point will achieve substantial completion in the spring of 2018. The majority of construction has been completed; however, some additional construction work and testing is required before Wildcat Point becomes commercially operable and available for dispatch by PJM to meet a portion of our member distribution cooperatives' power requirements. WOPC, the EPC contractor, claims that 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. See "Item 3 – Legal Proceedings."

Through December 31, 2017, we capitalized construction costs related to Wildcat Point totaling $789.7 million, including $77.8 million of capitalized interest, offset by $53.2 million of liquidated damages. We do not believe we have any additional liability associated with WOPC's claims; and therefore, we continue to estimate that the total project cost, after consideration of liquidated damages, is consistent with our original project cost estimate of $834.3 million.

Critical Accounting Policies

The preparation of our financial statements in conformity with generally accepted accounting principles requires that our management make estimates and assumptions that affect the amounts reported in our financial statements. We base these estimates and assumptions on information available as of the date of the financial statements. We consider the following accounting policies to be critical accounting policies due to the estimation involved in each.

Accounting for Regulated Operations

We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Accounting for Regulated Operations. In accordance with Accounting for Regulated Operations, certain of our revenues and expenses can be deferred at the discretion of our board of directors, which has budgetary and rate setting authority, if it is probable that these amounts will be recovered or returned through our formula rate in future periods. Regulatory assets represent costs that we expect to recover from our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. Regulatory liabilities represent probable future reductions in our revenues associated with amounts that we expect to return to our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. See "Factors Affecting Results—Formula Rate" below. Regulatory assets are generally included in deferred charges and regulatory liabilities are generally included in deferred credits and other liabilities. Deferred energy, which can be either a regulatory asset or regulatory liability, is included in current assets or current liabilities, respectively. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses, respectively, concurrent with their recovery through rates.

Deferred Energy

In accordance with Accounting for Regulated Operations, we use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Deferred energy on our Consolidated Statements of Revenues, Expenses, and Patronage Capital represents the difference between energy revenues, which are based upon energy rates approved by our board, and energy expenses, which are based upon actual energy costs incurred. The deferred energy balance on our Consolidated Balance Sheet represents the net accumulation of any under- or over-collection of energy costs. Under-collected energy costs appear as an asset and will be collected from our member distribution cooperatives in subsequent periods through our formula rate. Conversely, over-collected energy costs appear as a liability and will be returned to our member distribution cooperatives in subsequent periods through our formula rate.

In January 2018, the mid-Atlantic region experienced extremely cold weather, which increased our member distribution cooperatives' customers' requirements for power as well as increased our purchased power and fuel expenses. As a result, we currently anticipate that our January 31, 2018, deferred energy balance will be an under-collection of energy costs of approximately $52.4 million.

Margin Stabilization

Margin Stabilization allows us to review our actual demand-related costs of service and demand revenues and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formula rate allows us to recover and return amounts utilizing Margin Stabilization. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, generally in the succeeding calendar year. We adjust operating revenues and accounts receivable–members or accounts payable–members, as appropriate, to reflect these adjustments. These adjustments are treated as due, owed, incurred, and accrued for the year to which the adjustment relates. See "Factors Affecting Results—Formula Rate" below. The following table details the reduction in revenues utilizing Margin Stabilization for the past three years:

	Year Ended December 31,		
	2017	**2016**	**2015**
		(in thousands)	
Margin Stabilization adjustment	$ 34,144	$ 15,123	$ 9,561

Accounting for Asset Retirement and Environmental Obligations

Accounting for Asset Retirement and Environmental Obligations requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Asset retirement obligations currently reported on our Consolidated Balance Sheet were measured during a period of historically low interest rates. The impact on measurements of new asset retirement obligations using different rates in the future may be significant.

A significant portion of our asset retirement obligations relates to our share of the future cost to decommission North Anna. As of December 31, 2017 and 2016, North Anna's nuclear decommissioning asset retirement obligation totaled $105.8 million, or 83.7% of total asset retirement obligations, and $101.6 million, or 84.6% of our total asset retirement obligations, respectively. Because of its significance, the following discussion of critical third-party assumptions inherent in determining the fair value of asset retirement obligations relates to assumptions associated with our nuclear decommissioning obligations.

Approximately every four years, a new decommissioning study for North Anna is performed by third-party experts. The third-party experts provide us with periodic site-specific “base year” cost studies in order to estimate the nature, cost, and timing of planned decommissioning activities for North Anna. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption. Our current estimate is based on a study that was performed in 2014 and adopted effective December 1, 2014. We are not aware of any events that have occurred since the 2014 study that would materially impact our estimate. See "Note 3 of the Notes to Consolidated Financial Statements" in Item 8.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities. The following table details the weighted average cost escalation rates used by the study:

Year Study Performed	**Weighted Average Cost Escalation Rate**
2002	3.27%
2005	2.42
2009	2.30
2014	2.04

The weighted average cost escalation rate was applied if the cash flows increased as compared to the previous study. The original weighted average cost escalation rate was applied if the cash flows decreased as compared to the previous study. The use of alternative rates would have been material to the liabilities recognized. For example, had we increased the cost escalation rates by 0.5%, the amount recognized as of December 31, 2017, for our asset retirement obligations related to nuclear decommissioning would have been $20.2 million higher.

Accounting for Derivatives and Hedging

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of these forward purchase derivative contracts qualify for the normal purchases/normal sales accounting exception under Accounting for Derivatives and Hedging. As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the physically-delivered forward contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for our facilities which utilize natural gas. These derivatives do not qualify for the normal purchases/normal sales accounting exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we defer all unrealized gains and losses on a net basis as a regulatory liability or regulatory asset, respectively, in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense on our Consolidated Statements of Revenues, Expenses, and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported at fair value on our Consolidated Balance Sheet in the regulatory assets or regulatory liabilities account and deferred charges–other and deferred credits and other liabilities–other. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications.

Factors Affecting Results

Margins

We operate on a not-for-profit basis and, accordingly, seek to generate revenues sufficient to recover our cost of service and produce margins sufficient to establish reasonable reserves, meet financial coverage requirements, and accumulate additional equity approved by our board of directors. On November 7, 2017, our board of directors approved an additional equity contribution of $14.1 million. Revenues in excess of expenses in any year are designated as net margin attributable to ODEC on our Consolidated Statements of Revenues, Expenses, and Patronage Capital. We designate retained net margins attributable to ODEC on our Consolidated Balance Sheet as patronage capital, which we assign to each of our members on the basis of its class of membership and business with us. On November 7, 2017, our board of directors declared a patronage capital retirement of $14.1 million, to be paid on April 2, 2018. As a result of this declaration, we reduced patronage capital and increased accounts payable–members by $14.1 million.

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.

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

Energy costs, which are primarily variable costs, such as nuclear, coal, and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate rates, the base energy rate and the energy adjustment rate. The base energy rate is developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the base energy rate is reset in accordance with our budget and the energy adjustment rate is reset to zero. With board approval, we can revise the energy adjustment rate at any time during the year if it becomes apparent that the combined base energy rate and the current energy adjustment rate are over-collecting or under-collecting our actual and anticipated energy costs. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part I, Item 3.

Demand costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional equity contributions approved by our board of directors, are recovered through our demand rates. The formula rate allows us to change the actual demand rates we charge as our demand-related costs change, without FERC approval, with the exception of decommissioning cost, which is a fixed number in the formula rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, depreciation studies are required to be filed with FERC for its approval if they would result in a change in our depreciation rates. We collect our total demand costs through the following three separate rates:

- transmission service rate – designed to collect transmission-related and distribution-related costs;
- RTO capacity service rate – a proxy rate based on capacity prices in PJM that PJM allocates to ODEC and all other PJM members; and

- remaining owned capacity service rate – recovers all remaining demand costs not billed and/or recovered under the transmission service and RTO capacity service rates.

As stated above, our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. We establish our demand rates to produce a net margin attributable to ODEC equal to 20% of our budgeted total interest charges plus additional equity contributions approved by our board of directors.

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

We may revise our budget at any time to the extent that our current budget does not accurately reflect our costs and expenses or estimates of our sales of power. Increases or decreases in our budget automatically amend the energy and/or the demand components of our formula rate, as necessary. The formula rate also permits us to adjust revenues from the member distribution cooperatives to equal our actual total demand costs. We make these adjustments utilizing Margin Stabilization. See "Critical Accounting Policies—Margin Stabilization" above. 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.

Recognition of Revenue

Our operating revenues reflect the actual demand-related costs we incurred plus the energy costs that we collected. Estimated demand-related costs are collected during the period through the demand components of our formula rate. In accordance with Margin Stabilization, these costs, as well as operating revenues, are adjusted at the end of each reporting period to reflect actual demand-related costs incurred during that period. See "Critical Accounting Policies—Margin Stabilization" above. Estimated energy costs are collected during the period through the energy components of our formula rate. Operating revenues are not adjusted at the end of each reporting period to reflect actual energy costs incurred during that period. The difference between actual energy costs incurred and energy costs collected during each period is recorded as deferred energy expense, which may be a positive or negative number. See "Critical Accounting Policies—Deferred Energy" above.

We bill energy to each of our member and non-member customers based on the total MWh delivered to them each month. We bill demand costs through three separate rates: a transmission service rate, an RTO capacity service rate, and a remaining owned capacity service rate. See "—Formula Rate" above. The transmission service rate is billed to each of our member distribution cooperatives based on its contribution to the single zonal coincident peak (the hour of the month the need for energy is highest) for the prior year within each of the PJM transmission zones. The RTO capacity service rate is billed to each of our member distribution cooperatives based on its contribution to the average of the five hourly PJM coincident peaks in the prior year, subject to add-backs for participation in PJM demand response programs. The remaining owned capacity service rate is billed to each of our member distribution cooperatives based on its contribution to the monthly zonal coincident peak.

Customers' Requirements for Power

Changes in the number of customers and those customers' requirements for power significantly affect our member distribution cooperatives' customers' requirements for power. Factors affecting our member distribution cooperatives' customers' requirements for power include:

- *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 past three years were as follows:

	2017	2016	2015
Heating degree days	2,875	3,217	3,492
Cooling degree days	1,182	1,519	1,369

- *Economy* – General economic conditions have an impact on the rate of growth of our member distribution cooperatives' energy requirements.
- *Residential growth* – Residential growth in our member distribution cooperatives' service territories and increases in consumption levels increase the requirements for power.
- *Commercial growth* – The amount, size, and usage of electronics and machinery and the expansion of operations among our member distribution cooperatives' commercial and industrial customers impact the requirements for power.
- *Behind-the-meter (distributed generation) resources* – Growth in the number of consumers who serve all or a portion of their electricity requirements from resources behind-the-meter, such as solar panels or local micro-grids, reduces the requirements for power.

For additional discussion of our member distribution cooperatives' customers, see "Members—Member Distribution Cooperatives—Service Territories and Customers" in Item 1.

Power Supply Resources

In an attempt to provide stable power costs to our member distribution cooperatives, we utilize a combination of our owned generating resources and purchases from the market. We also regularly evaluate options for future power sources, including additional owned generation and power purchase contracts.

Market forces influence the structure and price of new power supply contracts into which we enter. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we rely on models based on our judgments and assumptions of factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas, used to generate electricity. Our actual results may vary from what our models predict, which may in turn impact our resulting costs to our members. Additionally, our models become less reliable the further into the future that the estimates are made. See "Risk Factors" in Item 1A.

In 2017, our generation facilities satisfied approximately 73.4% of our PJM capacity obligation and 36.7% of our energy requirements. We obtained the remainder of our PJM capacity obligation through the PJM RPM capacity auction process and purchased capacity contracts. The energy requirements not met by our owned generating facilities were obtained from multiple suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. See "Business—Power Supply Resources" in Item 1 and "Properties" in Item 2.

We are currently constructing an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. See "Wildcat Point" above.

PJM

PJM is an RTO that serves all of Delaware and Maryland, and most of Virginia, as well as other areas outside our member distribution cooperatives' service territories. We are a member of PJM and are therefore subject to the operations of PJM. PJM coordinates and establishes policies for the generation, purchase, and sale of capacity and energy in the control areas of its members, including all of the service territories of our member distribution cooperatives. As a result, our generating facilities are under dispatch control of PJM.

PJM balances its participants' power requirements with the power resources available to supply those requirements. Based on this evaluation of supply and demand, PJM schedules and dispatches available generating facilities throughout its region in a manner intended to meet the demand for energy in the most reliable and cost-effective manner. Thus, PJM directs the dispatch of these facilities even though it does not own them. When PJM cannot dispatch the most economical generating facilities due to transmission constraints, PJM will dispatch more expensive generating facilities to meet power requirements. For these reasons, actions by PJM may materially affect our operating results. PJM compensates us for the capacity of our generating facilities made available without regard to whether our generating facilities are dispatched. See "Business—Power Supply Resources—PJM" in Item 1.

We transmit power to our member distribution cooperatives through the transmission facilities subject to PJM operational control. We have agreements with PJM which provide us with access to transmission facilities under PJM's control as necessary to deliver energy to our member distribution cooperatives. We own a limited amount of transmission facilities. See "Properties—Transmission" in Item 2.

Transmission owners within PJM have made significant investments in their transmission systems. Because transmission rates are established to recover the cost of investment plus a return on the investment, PJM's rates for network transmission services have increased significantly in recent years. Our transmission costs are impacted each year by billing determinants, which are based on our usage during the peak hour of the year for each transmission area. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operating Expenses" in Item 7.

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 will be 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. For further discussion on Wholesale Power Contracts, see "Business—Members—Member Distribution Cooperatives—Wholesale Power Contracts" in Item 1.

Retail Choice in Virginia

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

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. See “PJM” above. 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.

Operational Availability

The operational availability of our owned generating resources for the past three years was as follows:

	Year Ended December 31,		
	2017	**2016**	**2015**
Clover	78.8%	91.0%	84.4%
North Anna	95.3	89.7	96.5
Louisa	93.4	98.2	97.2
Marsh Run	96.8	96.8	95.7
Rock Springs	95.4	79.6	79.9

In the fall of 2016, both units at Rock Springs experienced unscheduled outages that lasted approximately 55 and 56 days, respectively. Both units were available for operation in early December 2016. In the fall of 2015, both units at Rock Springs experienced unscheduled outages that lasted approximately 67 and 71 days, respectively.

Capacity Factor

The output of Clover and North Anna for the past three years as a percentage of maximum dependable capacity rating of the facilities was as follows:

	Year Ended December 31,		
	2017	**2016**	**2015**
Clover	43.5%	71.6%	72.1%
North Anna	97.3	91.0	98.2

Due to outages and economic dispatch by PJM, both units at Clover experienced reduced dispatch during 2017.

Outages

The scheduled and unscheduled outages for Clover and North Anna for the past three years were as follows:

	Clover Year Ended December 31,			North Anna Year Ended December 31,		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
		(in days)			(in days)	
Scheduled	104.3	35.1	86.4	30.6	71.1	20.5
Unscheduled	50.2	30.7	27.8	3.7	4.3	5.3
Total	154.5	65.8	114.2	34.3	75.4	25.8

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.

The scheduled and unscheduled outages for Clover in 2017, 2016, and 2015 were related to maintenance items associated with the boiler and balance of plant equipment.

Each unit at North Anna is scheduled for refueling approximately every 18 months. While only one unit is refueled at a time, this refueling schedule typically results in both units being off-line for refueling during the same calendar year once every three years. During 2017 and 2015, one unit at North Anna was off-line for refueling. During 2016, both units at North Anna were off-line for refueling.

Changing Environmental Regulation

We are subject to extensive federal and state regulation regarding environmental matters. This regulation is becoming increasingly stringent through amendments to federal and state statutes and the development of regulations authorized by existing law. Future federal and state legislation and regulations present the potential for even greater obligations to limit the impact on the environment from the operation of our generating and transmission facilities. See "Business—Regulation— Environmental" in Item 1 and "Risk Factors" in Item 1A.

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. See "—Customers' Requirements for Power" above. Our formula rate is based on our cost of service in meeting these requirements. See "—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 by type of purchaser and our energy sales in MWh for the past three years were as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Revenues from sales to:			
Member distribution cooperatives			
Energy revenues	$ 412,368	$ 498,044	$ 607,342
Demand revenues	319,208	349,050	361,583
Total revenues from sales to member distribution cooperatives	731,576	847,094	968,925
Non-members	21,531	30,777	51,103
Total operating revenues	$ 753,107	$ 877,871	$ 1,020,028
Energy sales to:		(in MWh)	
Member distribution cooperatives	11,419,738	11,961,760	12,688,672
Non-members	458,763	693,288	1,193,034
Total energy sales	11,878,501	12,655,048	13,881,706
Average cost of energy to member distribution cooperatives (per MWh)	$ 36.11	$ 41.64	$ 47.86
Average total cost to member distribution cooperatives (per MWh)	$ 64.06	$ 70.82	$ 76.36

Revenues for the past three years were as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Sales to member distribution cooperatives excluding renewable energy credit sales	$ 731,557	$ 844,539	$ 966,752
Renewable energy credit sales to member distribution cooperatives	19	2,555	2,173
Total Sales to Member Distribution Cooperatives	$ 731,576	$ 847,094	$ 968,925

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Sales to non-members excluding renewable energy credit sales	$ 16,356	$ 21,645	$ 42,556
Renewable energy credit sales to non-members	5,175	9,132	8,547
Total Sales to Non-members	$ 21,531	$ 30,777	$ 51,103

Member Distribution Cooperatives

In 2017, total revenues from sales to our member distribution cooperatives decreased $115.5 million, or 13.6%, as compared to 2016 primarily due to the decrease in energy revenues. Energy revenues decreased $85.7 million, or 17.2%, due to the 13.3% decrease in the average total cost of energy sold to our member distribution cooperatives and the 4.5% decrease in energy sales in MWh to our member distribution cooperatives. The average cost of energy sold to our member distribution cooperatives was impacted by the rate decreases we implemented in 2016 and 2017 (see table below). The decrease in the volume of energy sales was primarily a result of the reduction in our load requirements related to a limited exception provision in our wholesale power contract and retail choice in Virginia. See "Factors Affecting Results—Limited Exception Under Wholesale Power Contracts and —Retail Choice in Virginia". These two events represented a 437,430 MWh load reduction in 2017, as compared to 2016. Additionally, we experienced milder weather in 2017. Demand revenues decreased $29.8 million, or 8.5%, primarily due to decreases in transmission expense and capacity-related purchased power expense, and the recovery of North Anna Unit 3 development costs; partially offset by the deferral of revenue and the increase in the additional equity contribution.

In 2016, total revenues from sales to our member distribution cooperatives decreased $121.8 million, or 12.6%, as compared to 2015, primarily due to the decrease in energy revenues. Energy revenues decreased $109.3 million, or 18.0%, due to the 13.0% decrease in the average total cost of energy sold to our member distribution cooperatives and the 5.7% decrease in energy sales in MWh to our member distribution cooperatives. The average total cost of energy sold to our member distribution cooperatives was impacted by the rate decreases we implemented in 2015 and 2016 (see table below). The decrease in the volume of energy sales was primarily a result of the reduction in our load requirements related to a limited exception provision in our wholesale power contract and retail choice in Virginia. These two events resulted in a 658,837 MWh load reduction in 2016.

The following table summarizes the changes to our total energy rate since 2015 which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Rate Change	% Change
January 1, 2015	(0.3)
July 1, 2015	(2.9)
January 1, 2016	(5.4)
April 1, 2016	(6.8)
September 1, 2016	(6.5)
January 1, 2017	(6.7)
January 1, 2018	11.1

Non-members

In 2017, revenues from sales to non-members decreased $9.2 million, or 30.0%, as compared to the same period in 2016, due to the $5.3 million, or 24.4%, decrease in revenue from sales of excess energy primarily due to a 33.8% decrease in the volume of excess energy sales, and the $4.0 million, or 43.3%, decrease in revenue from sales of renewable energy credits. We primarily sell excess energy to PJM at the prevailing market price at the time of sale. Excess energy is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, and changes in market conditions.

In 2016, revenues from sales to non-members decreased $20.3 million, or 39.8%, as compared to the same period in 2015, due to the 49.1% decrease in revenue from sales of excess energy primarily due to a 41.9% decrease in the volume of excess energy sales.

Operating Expenses

The following is a summary of the components of our operating expenses for the past three years.

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Fuel	$ 94,603	$ 138,391	$ 159,917
Purchased power	397,387	408,006	494,909
Transmission	97,302	121,456	113,622
Deferred energy	(43,698)	12,194	47,783
Operations and maintenance	48,508	50,088	49,768
Administrative and general	42,182	41,477	37,448
Depreciation and amortization	45,433	45,739	45,168
Amortization of regulatory asset/(liability), net	18,156	2,233	9,496
Accretion of asset retirement obligations	5,044	4,839	4,695
Taxes, other than income taxes	8,216	8,256	8,269
Total Operating Expenses	$ 713,133	$ 832,679	$ 971,075

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 $119.5 million, or 14.4%, for 2017 as compared to 2016, primarily as a result of the decreases in deferred energy, fuel expense, and transmission expense partially offset by the increase in amortization of regulatory asset/(liability), net.

- Deferred energy expense decreased $55.9 million. In 2017, we under-collected $43.7 million and in 2016, we over-collected $12.2 million. Deferred energy expense represents the difference between energy revenues and energy expenses.
- Fuel expense decreased $43.8 million, or 31.6%. Clover generation decreased 40.5%, due to reduced operational availability as a result of additional outage days and PJM's economic dispatch of the facility. Our combustion turbine facilities generation decreased 31.5% due to PJM's economic dispatch of the facilities.
- Transmission expense decreased $24.2 million, or 19.9%, primarily due to a decrease in PJM charges for network transmission services.
- Amortization of regulatory asset/(liability), net increased $15.9 million primarily due to our board of directors approval in 2017 of the deferral of $15.0 million in revenue to reduce future revenue requirements and to be amortized ratably in 2018.

Total operating expenses were $138.4 million, or 14.3% lower for 2016 as compared to 2015, primarily as a result of the decreases in purchased power expense, deferred energy, and fuel expense, partially offset by the increase in transmission.

- Purchased power expense, which includes the cost of purchased energy and capacity, decreased $86.9 million, or 17.6%, primarily due to the 12.5% decrease in the volume of purchased energy and the 4.2% decrease in the average cost of purchased energy. Purchased power volume decreased primarily due to the decrease in our member distribution cooperatives' power requirements from us during 2016.
- Deferred energy expense decreased $35.6 million. In 2016 and 2015, we over-collected $12.2 million and $47.8 million, respectively.
- Fuel expense decreased $21.5 million, or 13.5%, primarily due to the 20.7% decrease in the average cost of fuel for our combustion turbine facilities and the 7.8% decrease in the dispatch of our combustion turbine facilities.
- Transmission expense increased $7.8 million, or 6.9%, primarily due to an increase in PJM charges for network transmission services.

Other Items

Investment Income

Investment income increased $7.5 million in 2017, as compared to 2016, primarily due to increased earnings on our nuclear decommissioning trust. Investment income was relatively flat in 2016 as compared to 2015.

Interest Income on North Anna Unit 3 Cost Recovery

Interest income on North Anna Unit 3 cost recovery represents interest received from Virginia Power related to the recovery of a portion of our North Anna Unit 3 regulatory asset. In 2015, we recovered 70% of these costs from Virginia

Power and, with our board of directors' approval, amortized the remaining balance in 2015. On June 1, 2017, Virginia Power agreed to return the remaining balance of North Anna Unit 3 development costs that we incurred as part of the resolution of other regulatory matters with Virginia Power. The remaining balance of North Anna Unit 3 development costs, including interest through May 2018, totals $11.6 million. In the second quarter of 2017, we recorded $6.9 million as amortization of regulatory asset/liability, net, and $4.4 million as interest income on North Anna Unit 3 cost recovery on our Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital. During the second quarter of 2017, we received a payment of $6.8 million and established a receivable for the remaining balance, which will continue to accrue interest. Virginia Power agreed to pay the remaining balance in the second quarter of 2018. See "Note 10 of the Notes to Consolidated Financial Statements" in Item 8.

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 past three years were as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Interest on long-term debt	$ (59,441)	$ (56,983)	$ (58,065)
Interest on revolving credit facility	(2,384)	(1,368)	(710)
Other interest	(809)	(1,056)	(623)
Total interest charges	(62,634)	(59,407)	(59,398)
Allowance for borrowed funds used during construction	35,594	30,274	13,771
Interest charges, net	$ (27,040)	$ (29,133)	$ (45,627)

In 2017, interest charges, net decreased $2.1 million, or 7.2%, as compared to 2016, due to the $5.3 million increase in allowance for borrowed funds used during construction (capitalized interest) primarily related to Wildcat Point, partially offset by the $3.2 million increase in total interest charges. In 2016, interest charges, net decreased $16.5 million, or 36.1%, as compared to 2015, due to the $16.5 million increase in allowance for borrowed funds used during construction primarily related to Wildcat Point.

Net Margin Attributable to ODEC

In 2017, 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, increased $9.0 million, or 51.0%, primarily as a result of the $14.1 million equity contribution in 2017, as compared to the $5.8 million equity contribution in 2016. In 2016, net margin attributable to ODEC, increased $5.8 million, or 48.5%, as a result of the $5.8 million equity contribution in 2016. See "Factors Affecting Results—Formula Rate" above.

Financial Condition

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

- Long-term debt increased $208.3 million due to the $250 million issuance of long-term debt on July 6, 2017, slightly offset by scheduled long-term debt payments.
- Construction work in progress increased $85.7 million primarily due to expenditures related to Wildcat Point, slightly offset by electric plant placed in service.
- Revolving credit facility decreased $108.6 million due to the repayment of outstanding borrowings under this facility using the proceeds of the July 2017 debt issuance, partially offset by new borrowings.
- Accounts payable decreased $39.3 million primarily due to decreased payables for construction.

- Deferred energy changed $43.7 million as a result of the under-collection of our energy costs in 2017. The deferred energy balance was an asset of $3.7 million as of December 31, 2017 and a liability of $40.0 million as of December 31, 2016.

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

In 2017, 2016, and 2015, our operating activities provided cash flows of $56.5 million, $88.5 million, and $219.3 million, respectively. Operating activities in 2017 were primarily impacted by the following:

- Deferred energy changed $43.7 million due to the under-collection of energy costs in 2017.
- Current liabilities changed $16.3 million primarily due to the $9.6 million decrease in accounts payable and the $7.3 million decrease in accounts payable–members.
- Regulatory assets and liabilities changed $19.7 million primarily due to the establishment of a regulatory liability for deferred revenue.

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 December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings at a weighted average interest rate of 2.6% and $12.0 million in letters of credit. As of December 31, 2016, we had outstanding under this facility, $152.0 million in borrowings at a weighted average interest rate of 1.6% and $5.2 million in letters of credit.

The syndicated credit agreement contains customary events of default, which, if they occur, would terminate our ability to borrow amounts under this facility and potentially accelerate any outstanding loans under this facility at the election of the lenders. Some of these customary events of default relate to:

- our failure to timely pay any principal and interest due under the credit facility;
- a breach by us of our representations and warranties in the credit agreement or related documents;
- a breach of a covenant contained in the credit agreement, which, in some cases we are given an opportunity to cure and, in certain cases, includes a debt to capitalization financial covenant;
- failure to pay, when due, other indebtedness above a specified amount;
- an unsatisfied judgment above specified amounts;
- bankruptcy or insolvency events relating to us;
- invalidity of the credit agreement and related loan documentation or our assertion of invalidity; and
- a failure by our member distribution cooperatives to pay amounts in excess of an agreed threshold owing to us beyond a specified cure period.

Financings

We fund the portion of our capital expenditures that we are not able to fund from operations through borrowings under our revolving credit facility and financings in the debt capital markets. These capital expenditures consist primarily of the costs related to the development, construction, acquisition, or improvement of our owned generating facilities.

On July 6, 2017, we issued $250 million of long-term debt in a private placement transaction. The issuance consists of $250 million of 3.33% First Mortgage Bonds, 2017 Series A due December 1, 2037.

Uses

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

Capital Expenditures

We regularly forecast our capital expenditures as part of our long-term business planning activities. We review these projections periodically in order to update our calculations to reflect changes in our future plans, construction costs, market factors, and other items affecting our forecasts. Our actual capital expenditures could vary significantly from these projections. The table below summarizes our actual and projected capital expenditures on a cash flow basis, including capitalized interest, for 2015 through 2020:

	Actual Year Ended December 31,			Projected Year Ended December 31,		
	2015	2016	2017	2018	2019	2020
			(in millions)			
Wildcat Point	$ 331.7	$ 232.7	$ 118.2	$ 67.4	$ 2.5	$ 3.0
Clover	14.3	7.1	7.1	15.2	14.4	14.8
North Anna nuclear fuel	6.3	9.6	17.0	9.9	9.2	17.0
North Anna	9.2	6.5	3.5	11.4	18.8	31.9
Transmission	8.1	4.4	1.8	1.3	8.7	8.8
Combustion turbine facilities	2.3	0.9	4.9	0.6	0.9	0.4
Other	1.6	2.6	1.4	5.1	16.7	18.2
Total	$ 373.5	$ 263.8	$ 153.9	$ 110.9	$ 71.2	$ 94.1

Nearly all of our capital expenditures consist of additions to electric plant and equipment, particularly for the construction of Wildcat Point. Capital expenditures for "North Anna" include $3.0 million, $12.3 million, and $25.6 million, for 2018, 2019, and 2020, respectively, for costs related to license extension. Capital expenditures for "Other" include costs related to our administrative and general assets, and distributed generation facilities; and for 2018, 2019, and 2020, includes $3.4 million, $15.1 million, and $16.6 million, respectively, for planned solar projects. We intend to use our cash flow from operations, borrowings under our revolving credit facility, and financings in the debt capital markets to fund all of our currently projected capital requirements through 2020.

Contractual Obligations

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our generating facilities, power purchases for capacity and energy, the financing of our operations, and other matters. See "Business—Power Supply Resources—Power Purchase Contracts" in Item 1. The following table summarizes our long-term contractual obligations at December 31, 2017:

	Payments due by Period				
	Total	2018	2019-2020	2021-2022	2023 and Thereafter
			(in millions)		
Long-term debt obligations	$ 2,207.7	$ 100.0	$ 193.8	$ 201.5	$ 1,712.4
Power purchase obligations	473.1	203.5	268.3	1.3	—
Asset retirement obligations	388.9	0.9	—	—	388.0
Operating lease obligations	111.5	109.1	1.0	1.0	0.4
Construction obligations	24.6	24.6	—	—	—
Total	$ 3,205.8	$ 438.1	$ 463.1	$ 203.8	$ 2,100.8

We expect to fund these obligations with cash flow from operations, borrowings under our revolving credit facility, and financings in the debt capital markets.

Long-term Debt Obligations

At December 31, 2017, our long-term debt obligations include long-term debt issued privately and to the public under the Indenture. Long-term debt includes both the principal of and interest on long-term debt, and long-term debt due within one year.

Power Purchase Obligations

As part of our power supply strategy, we entered into a number of agreements for the purchase of capacity or energy, or both, in order to meet our member distribution cooperatives' requirements. See "Business—Power Supply Resources—Power Purchase Contracts" in Item 1.

Asset Retirement Obligations

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

Operating Lease Obligations

Our obligation described above with respect to operating lease obligations primarily relates to our portion of the Clover Unit 1 purchase option price at the end of the term of the leaseback that will be satisfied by our investment in United States Treasury securities. See "Significant Contingent Obligations—Clover Lease" below.

Construction Obligations

Our construction obligations include payments related to Wildcat Point EPC contractor payments and major equipment purchase contracts. See "Overview—Wildcat Point" above.

Significant Contingent Obligations

In addition to these existing contractual obligations, we have significant contingent obligations. These obligations primarily relate to power purchase arrangements, our arrangement with TEC, and as of December 31, 2017, our lease of our interest in Clover Unit 1. Some of our power purchase contracts obligate us to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's.

Power Purchase Arrangements

Under the terms of most of our hedging instruments, we typically agree to provide collateral under certain circumstances and we require comparable terms from our counterparties. The collateral we may be required to post with a counterparty, and vice versa, is normally a function of the collateral thresholds we negotiate with a counterparty relative to a range of credit ratings as well as the value of our transaction(s) under a contract with a respective counterparty. As of December 31, 2017, the collateral we had posted with counterparties pursuant to the hedging instruments we have in place totaled $15.2 million. Typically, collateral thresholds under our contracts are zero once an entity is rated below investment grade by S&P or Moody's (i.e., "BBB-" or "Baa3," respectively). As of December 31, 2017, if our credit ratings had been below investment grade we estimate we would have been obligated to post between $350 million and $450 million of collateral with our counterparties. This calculation is based on energy prices on December 31, 2017, and delivered power for which we have not yet paid. Depending on the difference between the price of power under our contracts and the price of power in the market at the time of the calculation, this amount could increase or decrease.

Additionally, in accordance with its credit policy, PJM subjects each applicant, participant and member of PJM to a credit evaluation to determine its creditworthiness, and whether it must provide any collateral to support its obligations in connection with its PJM transactions. A material change in our financial condition, including the downgrading of our credit rating by any rating agency, could cause PJM to re-evaluate our creditworthiness and require that we provide collateral. As of December 31, 2017, if PJM had determined that we needed to provide collateral to support our obligations, PJM could have asked us to provide up to approximately $9.8 million.

TEC Guarantees

TEC is considered a variable interest entity for which we are the primary beneficiary, and we have consolidated its results and eliminated all intercompany balances and transactions in consolidation. To facilitate the ability of TEC to sell power in the market, we have agreed to guarantee up to a maximum of $200 million of TEC's delivery and payment obligations associated with its energy trades, if requested. See "Business—Members—TEC" in Item 1. Our agreement to guarantee these obligations continues in effect until we elect to terminate it by providing at least 30 days' prior written notice of termination or until all amounts owed to us by TEC have been paid. Our guarantee of TEC's obligations will enable it to maintain sufficient credit support to meet its delivery and payment obligations associated with its energy trades. As of December 31, 2017, we did not have any guarantees outstanding in support of TEC's obligations.

Clover Lease

In 1996, we entered into a lease transaction relating to our 50% undivided ownership interest in Clover Unit 1 and related common facilities. In this transaction, we leased our undivided interest in the facility to an owner trust for the benefit of an investor for the full productive life of the unit in exchange for a one-time rental payment at the beginning of the lease. Immediately after the lease to the owner trust, we leased the unit and common facilities back for a term of 21.8 years and agreed to make periodic rental payments to the owner trust.

We used a portion of the one-time rental payment of $315.0 million we received to enter into a payment undertaking agreement and to purchase an investment that would provide for substantially all of our periodic rent payments under the leaseback, and the fixed purchase price of the interest in the unit at the end of the term of the leaseback if we were to exercise our option to purchase the interest of the owner trust in the unit at that time. As of December 31, 2017, the payment undertaking agreement had a balance of $304.7 million, and the amount of debt considered to be extinguished by in substance defeasance was $304.7 million.

We elected to purchase the owner trust's interest in the unit and terminate the lease effective January 5, 2018, for a fixed purchase price of $430.5 million. On January 5, 2018, payments under the payment undertaking agreement funded $289.7 million of this amount, and $32.2 million was provided by us and in turn paid to us as the holder of a loan to the owner trust. The remaining balance of the fixed purchase price is funded by United States Treasury securities with a maturity value of $108.6 million and will be paid in four installments during 2018.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as of and after January 5, 2018, the date on which the Clover Unit 1 lease arrangements terminated.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The operation of our business exposes us to several common market risks, including changes in market prices for power and fuel, and interest rates and equity prices.

Market Price Risk

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. See "Business—Power Supply Resources" in Item 1. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk.

The fair value of the hedging instruments we use to mitigate market price risk is impacted by changes in market prices. As of December 31, 2017, we estimate that the fair value of our purchased power agreements and forward purchases of natural gas was between $800 million and $900 million. Approximately 31% of the fair value of this portfolio is estimable using observable market prices. The remaining 69% of the fair value of this portfolio is related to less liquid products and the fair values of these products are not directly estimable using observable market prices. In the absence of observable market prices, the valuation of the 69% of this portfolio that relates to less liquid products involves management judgment, the use of estimates, and the underlying assumptions in our portfolio model. As a result, changes in estimates and underlying assumptions or use of alternate valuation methods could affect the estimated fair value of this portfolio. As an example of our portfolio's exposure to market price risk, we estimate that a 10% change in the price of the commodities hedged by the portion of this portfolio with observable market prices would have changed the fair value of this portion of the portfolio by approximately $25.9 million as of December 31, 2017. To the extent all or portions of our portfolio are liquidated above or below our original cost, these gains or losses are factored into the costs billed to our member distribution cooperatives pursuant to our formula rate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate" in Item 7.

We have formulated policies and procedures to manage the risks associated with these market price fluctuations. Additionally, we use various hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. ACES assists us in managing our market price risks by:

- maintaining a portfolio model that identifies our power producing resources (including our power purchase contract positions and generating capacity, and fuel supply, transportation, and storage arrangements) and analyzing the optimal use of these resources in light of costs and market risks associated with using these resources;
- modeling our power obligations and assisting us with analyzing alternatives to meet our member distribution cooperatives' power requirements;
- selling excess power as our agent; and
- executing hedge trades to stabilize the cost of fuel requirements, primarily natural gas used to operate our generating facilities.

We also are subject to market price risk relating to purchases of fuel for Clover and North Anna. We manage these risks indirectly through our participation in the management arrangements for these facilities. However, Virginia Power, as operator of these facilities, has the sole authority and responsibility to procure coal and nuclear fuel for Clover and North Anna, respectively.

Virginia Power advises us that it uses both long-term contracts and short-term spot agreements to acquire the low sulfur bituminous coal used to fuel Clover. See “Business—Power Supply Resources—Fuel Supply—Coal” in Item 1.

Virginia Power advises us that it primarily uses long-term contracts to support North Anna’s nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices, which are dependent upon the market environment. See “Business—Power Supply Resources—Fuel Supply—Nuclear” in Item 1.

Interest Rate Risk and Equity Price Risk

In 2017, all of our outstanding long-term debt accrued interest at fixed rates.

We maintain a revolving credit facility. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Sources—Revolving Credit Facility” in Item 7. Any amounts we borrow under this facility will accrue interest at a variable rate. As of December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings at a weighted average interest rate of 2.6% and $12.0 million in letters of credit.

We accrue decommissioning costs over the expected service life of North Anna and have made periodic deposits to a trust so that the trust balance will cover the estimated cost to decommission North Anna at the time of decommissioning. As of December 31, 2017, $124.0 million, $59.4 million, and $0.3 million were invested in equity securities, debt securities, and cash, respectively. The value of these debt and equity securities will be impacted by changes in interest rates and price fluctuations in equity markets. To minimize adverse changes in the aggregate value of the trust, we actively monitor our portfolio by measuring the performance of the investments against market indices and by maintaining and reviewing established target allocation percentages of assets in the trust to various investment options. We believe the trust’s exposure to changes in interest rates and price fluctuations in equity markets will not have a material impact on our financial results.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED FINANCIAL STATEMENTS
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Report of Management on ODEC's Internal Control over Financial Reporting

Management of Old Dominion Electric Cooperative ("ODEC") has assessed ODEC's internal control over financial reporting as of December 31, 2017, based on criteria for effective internal control over financial reporting described in the "2013 Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that as of December 31, 2017, our system of internal control over financial reporting was properly designed and operating effectively based upon the specified criteria.

Management of ODEC is responsible for establishing and maintaining adequate internal control over financial reporting. ODEC's internal control over financial reporting is comprised of policies, procedures, and reports designed to provide reasonable assurance to ODEC's management and board of directors that the financial reporting and the preparation of the financial statements for external reporting purposes has been handled in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes those policies and procedures that (1) govern records to accurately and fairly reflect the transactions and dispositions of assets of ODEC; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of ODEC are being made only in accordance with authorizations of the management and directors of ODEC; and (3) provide reasonable safeguards against or timely detection of material unauthorized acquisition, use or disposition of ODEC's assets.

Internal controls over financial reporting may not prevent or detect all misstatements. Accordingly, even effective internal control can provide only reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

March 14, 2018

/s/ ROBERT L. KEES

Robert L. Kees
Interim President and Chief Executive Officer and
Senior Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Members of Old Dominion Electric Cooperative

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Old Dominion Electric Cooperative (the Cooperative) as of December 31, 2017 and 2016, and the related consolidated statements of revenues, expenses, and patronage capital, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Cooperative at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on the Cooperative's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Cooperative in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement are free of material misstatement, whether due to error or fraud. The Cooperative is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provides a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Cooperative's auditor since 2000.
Richmond, Virginia
March 14, 2018

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2017 AND 2016

	2017	2016
ASSETS:	(in thousands)	
Electric Plant:		
Property, plant, and equipment	$ 1,754,236	$ 1,746,852
Less accumulated depreciation	(891,701)	(855,068)
Net Property, plant, and equipment	862,535	891,784
Nuclear fuel, at amortized cost	18,089	22,138
Construction work in progress	822,667	736,996
Net Electric Plant	1,703,291	1,650,918
Investments:		
Nuclear decommissioning trust	183,681	159,155
Lease deposits	106,812	104,514
Unrestricted investments and other	7,009	6,599
Total Investments	297,502	270,268
Current Assets:		
Cash and cash equivalents	4,084	2,946
Accounts receivable	10,379	6,563
Accounts receivable–members	83,133	85,116
Fuel, materials, and supplies	52,766	56,353
Deferred energy	3,669	—
Prepayments and other	5,274	4,737
Total Current Assets	159,305	155,715
Deferred Charges:		
Regulatory assets	45,284	49,682
Other	3,780	3,533
Total Deferred Charges	49,064	53,215
Total Assets	$ 2,209,162	$ 2,130,116
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 415,384	$ 402,857
Non-controlling interest	5,744	5,725
Total Patronage capital and Non-controlling interest	421,128	408,582
Long-term debt	1,198,396	990,083
Revolving credit facility	43,400	152,000
Total long-term debt and revolving credit facility	1,241,796	1,142,083
Total Capitalization	1,662,924	1,550,665
Current Liabilities:		
Long-term debt due within one year	40,792	28,292
Accounts payable	92,259	131,581
Accounts payable–members	59,064	66,380
Accrued expenses	6,391	5,806
Deferred energy	—	40,029
Regulatory liability-revenue deferral	15,000	—
Obligations under long-term lease	103,683	—
Total Current Liabilities	317,189	272,088
Deferred Credits and Other Liabilities:		
Asset retirement obligations	126,470	120,083
Obligations under long-term lease	—	96,930
Regulatory liabilities	101,237	89,020
Other	1,342	1,330
Total Deferred Credits and Other Liabilities	229,049	307,363
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,209,162	$ 2,130,116

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

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF REVENUES, EXPENSES, AND PATRONAGE CAPITAL FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

	2017	2016	2015
		(in thousands)	
Operating Revenues	$ 753,107	$ 877,871	$ 1,020,028
Operating Expenses:			
Fuel	94,603	138,391	159,917
Purchased power	397,387	408,006	494,909
Transmission	97,302	121,456	113,622
Deferred energy	(43,698)	12,194	47,783
Operations and maintenance	48,508	50,088	49,768
Administrative and general	42,182	41,477	37,448
Depreciation and amortization	45,433	45,739	45,168
Amortization of regulatory asset/(liability), net	18,156	2,233	9,496
Accretion of asset retirement obligations	5,044	4,839	4,695
Taxes, other than income taxes	8,216	8,256	8,269
Total Operating Expenses	713,133	832,679	971,075
Operating Margin	39,974	45,192	48,953
Other expense, net	(3,826)	(3,811)	(3,339)
Investment income	12,950	5,411	5,519
Interest income on North Anna Unit 3 cost recovery	4,598	—	6,393
Interest charges, net	(27,040)	(29,133)	(45,627)
Income taxes	(11)	(1)	(3)
Net Margin including Non-controlling interest	26,645	17,658	11,896
Non-controlling interest	(18)	(21)	(17)
Net Margin attributable to ODEC	26,627	17,637	11,879
Patronage Capital - Beginning of Period	402,857	390,976	379,097
Patronage Capital – Retirement	(14,100)	(5,756)	—
Patronage Capital - End of Period	$ 415,384	$ 402,857	$ 390,976

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

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

	2017	2016	2015
		(in thousands)	
Operating Activities:			
Net Margin including Non-controlling interest	$ 26,645	$ 17,658	$ 11,896
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	45,433	45,739	45,168
Other non-cash charges	18,899	18,177	18,706
Amortization of lease obligations	6,753	6,308	5,893
Interest on lease deposits	(3,045)	(2,984)	(2,910)
Change in current assets	1,217	11,151	(2,871)
Change in deferred energy	(43,698)	12,194	47,783
Change in current liabilities	(16,339)	(36,449)	62,694
Change in regulatory assets and liabilities	19,683	17,882	26,968
Change in deferred charges-other and deferred credits and other liabilities-other	950	(1,224)	5,973
Net Cash Provided by Operating Activities	56,498	88,452	219,300
Investing Activities:			
Purchases of held to maturity securities	(3,723)	(480)	(130,293)
Proceeds from sale of held to maturity securities	4,024	960	130,240
Increase in other investments	(12,522)	(4,300)	(4,726)
Electric plant additions	(153,856)	(263,777)	(373,516)
Net Cash Used for Investing Activities	(166,077)	(267,597)	(378,295)
Financing Activities:			
Issuance of long-term debt	250,000	—	332,000
Debt issuance costs	(2,391)	—	(1,754)
Payments of long-term debt	(28,292)	(28,292)	(28,292)
Draws on revolving credit facility	385,400	333,850	104,000
Repayments on revolving credit facility	(494,000)	(181,850)	(190,000)
Net Cash Provided by Financing Activities	110,717	123,708	215,954
Net Change in Cash and Cash Equivalents	1,138	(55,437)	56,959
Cash and Cash Equivalents - Beginning of Period	2,946	58,383	1,424
Cash and Cash Equivalents - End of Period	$ 4,084	$ 2,946	$ 58,383

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—Summary of Significant Accounting Policies

General

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative and 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 December 31, 2017 and December 31, 2016. The income taxes reported on our Consolidated Statements of Revenues, Expenses, and Patronage Capital relate to the tax provision for TEC, which is a taxable corporation. As TEC is 100% owned by our Class A members, its equity is presented as a non-controlling interest on our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities for which we have significant influence is recorded using the equity method of accounting. We have a power sales contract with TEC under which we may sell to TEC, power that we do not need to meet the needs of our member distribution cooperatives. TEC then sells this power to the market under market-based rate authority granted by FERC. Additionally, we have a separate contract under which we may purchase natural gas from TEC. TEC does not engage in speculative trading.

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 customers located in Virginia, Delaware, and Maryland. Our sole Class B member is TEC. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. Our rates are set periodically by a formula that was accepted for filing by FERC, and 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 prescribed by FERC. In conformity with GAAP, the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

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

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

Electric Plant

Electric plant is stated at original cost when first placed in service. Such cost includes contract work, direct labor and materials, allocable overhead, an allowance for borrowed funds used during construction and asset retirement costs. Upon the partial sale or retirement of plant assets, the original asset cost and current disposal costs less sale proceeds, if any, are charged or credited to accumulated depreciation. In accordance with industry practice, no profit or loss is recognized in connection with normal sales and retirements of property units.

Maintenance and repair costs are expensed as incurred. Replacements and renewals of items considered to be units of property are capitalized to the property accounts.

Depreciation

We use the group method of depreciation and conduct depreciation studies approximately every five years. Our last depreciation study was performed in 2016 and implemented in 2017. Our depreciation rates were as follows:

Generating Facility	Depreciation Rates 2017	2016	2015
Clover	1.9%	1.8%	1.8%
North Anna	3.3	3.0	3.0
Louisa	3.1	3.5	3.5
Marsh Run	3.0	3.2	3.2
Rock Springs	3.1	3.3	3.3

Nuclear Fuel

Nuclear fuel is amortized on a unit of production basis sufficient to fully amortize the cost of fuel over its estimated service life and is recorded in fuel expense.

Virginia Power, as operating agent of North Anna, has the sole authority and responsibility to procure nuclear fuel for the facility. Virginia Power advises us that it primarily uses long-term contracts to support North Anna's nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices, which are dependent upon the market environment. We are not a direct party to any of these procurement contracts and we do not control their terms or duration. Virginia Power advises us that current agreements, inventories, and spot market availability are expected to support North Anna's current and planned fuel supply needs for the near term and that additional fuel is purchased as required to attempt to ensure optimal cost and inventory levels.

Under the Nuclear Waste Policy Act of 1982, the DOE is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as North Anna, in accordance with contracts executed with the DOE. The DOE did not begin accepting spent fuel in 1998 as specified in its contract. As a result, Virginia Power sought reimbursement for certain spent nuclear fuel-related costs incurred and in 2012 signed a settlement agreement with the DOE. By mutual agreement of the parties, the settlement agreement is extendable to provide for resolution of damages. The settlement agreement has been extended to provide for periodic payments for damages incurred through December 31, 2019. We continue to recognize receivables for certain spent nuclear fuel-related costs. We believe the recovery of these costs from the DOE is probable. As of December 31, 2017 and 2016, we had an outstanding receivable of $2.9 million and $3.3 million, respectively.

Fuel, Materials, and Supplies

Fuel, materials, and supplies is primarily composed of fuel and spare parts for our generating assets, and renewable energy credits, all of which are recorded at cost. Fuel consists primarily of coal and No. 2 fuel oil.

Allowance for Borrowed Funds Used During Construction

Allowance for borrowed funds used during construction is defined as the net cost of borrowed funds used for construction purposes during the construction period and a reasonable rate on other funds when so used. We capitalize interest on borrowings for significant construction projects. Interest capitalized in 2017, 2016, and 2015, was $35.6 million, $30.3 million, and $13.8 million, respectively.

Income Taxes

We are a not-for-profit electric cooperative and are currently exempt from federal income taxation under IRC Section 501(c)(12), and we intend to continue to operate in this manner. Based on our assessment and evaluations of relevant authority, we believe we could sustain treatment as a tax-exempt utility in the event of a challenge of our tax status. Accordingly, no provision for income taxes has been recorded based on ODEC's operations in the accompanying consolidated financial statements.

TEC is a taxable corporation and its provision for income taxes was immaterial for the years ended December 31, 2017, 2016, and 2015.

Operating Revenues

Our operating revenues are derived from sales to our members and non-members and are recorded when power and renewable energy credits are delivered. We sell power to our member distribution cooperatives pursuant to long-term wholesale power contracts that we maintain with each of them. These wholesale power contracts obligate each member distribution cooperative to pay us for power furnished in accordance with our rates. See Note 5—Wholesale Power Contracts. Revenues from sales to our member distribution cooperatives for the past three years were as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Sales to member distribution cooperatives excluding renewable energy credit sales	$ 731,557	$ 844,539	$ 966,752
Renewable energy credit sales to member distribution cooperatives	19	2,555	2,173
Total Sales to Member Distribution Cooperatives	$ 731,576	$ 847,094	$ 968,925

We sell excess purchased and generated energy, if any, to TEC, or third parties under FERC market-based rate authority. 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; however, in 2017, 2016, and 2015, TEC had no sales to third parties. Excess purchased and generated energy that is not sold to TEC is sold to PJM under its rates for providing energy imbalance service, or to third parties. Revenues from sales to non-members for the past three years were as follows:

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Sales to non-members excluding renewable energy credit sales	$ 16,356	$ 21,645	$ 42,556
Renewable energy credit sales to non-members	5,175	9,132	8,547
Total Sales to Non-members	$ 21,531	$ 30,777	$ 51,103

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.

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

Energy costs, which are primarily variable costs, such as nuclear, coal, and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate rates, the base energy rate and the energy adjustment rate. The base energy rate is developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the base energy rate is reset in accordance with our budget and the energy adjustment rate is reset to zero. With board approval, we can revise the energy adjustment rate at any time during the year if it becomes apparent that the combined base energy rate and the current energy adjustment rate are over-collecting or under-collecting our actual and anticipated energy costs. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part I, Item 3.

Demand costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional equity contributions approved by our board of directors, are recovered through our demand rates. The formula rate allows us to change the actual demand rates we charge as our demand-related costs change, without FERC approval, with the exception of decommissioning cost, which is a fixed number in the formula rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, depreciation studies are required to be filed with FERC for its approval if they would result in a change in our depreciation rates. We collect our total demand costs through the following three separate rates:

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

As stated above, our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. We establish our demand rates to produce a net margin attributable to ODEC equal to 20% of our budgeted total interest charges plus additional equity contributions approved by our board of directors.

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

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

For the year ended December 31, 2017, our board of directors approved an additional equity contribution of $14.1 million and we recorded a reduction in operating revenues of $34.1 million, utilizing Margin Stabilization, to produce a net margin equal to 42.5% of our actual total interest charges. For the year ended December 31, 2016, our board of directors approved an additional equity contribution of $5.8 million and we recorded a reduction in operating revenues of $15.1 million utilizing Margin Stabilization, to produce a net margin equal to 29.7% of our actual total interest charges. For the year ended December 31, 2015, we recorded a reduction in operating revenues of $9.6 million, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.

Regulatory Assets and Liabilities

We account for certain revenues and expenses as a rate-regulated entity in accordance with Accounting for Regulated Operations. This allows certain of our revenues and expenses to be deferred at the discretion of our board of directors, which has budgetary and rate setting authority, if it is probable that these amounts will be recovered or returned through our formula rate in future periods. Regulatory assets represent costs that we expect to recover from our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. Regulatory liabilities represent probable future reductions in our revenues associated with amounts that we expect to return to our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. Regulatory assets are generally included in deferred charges and regulatory liabilities are generally included in deferred credits and other liabilities. Deferred energy, which can be either a regulatory asset or a regulatory liability, is included in current assets or current liabilities, respectively. See "Deferred Energy" below. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses, respectively, concurrent with their recovery through rates.

Debt Issuance Costs

Capitalized costs associated with the issuance of long-term debt totaled \$7.3 million and \$6.4 million as of December 31, 2017 and 2016, respectively, and are included as a direct reduction to long-term debt. Capitalized costs associated with our revolving credit facility totaled \$1.1 million and \$0.4 million as of December 31, 2017 and 2016, respectively, and are recorded in deferred charges–other. These costs are being amortized using the effective interest method over the life of the respective long-term debt issuances and revolving credit facility, and are included in interest charges, net.

Deferred Energy

In accordance with Accounting for Regulated Operations, we use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. The deferred energy balance represents the net accumulation of any under- or over-collection of energy costs. Under-collected energy costs appear as an asset and will be collected from our member distribution cooperatives in subsequent periods through our formula rate. Conversely, over-collected energy costs appear as a liability and will be returned to our member distribution cooperatives in subsequent periods through our formula rate.

As of December 31, 2017 and 2016, we had an under-collected deferred energy balance of \$3.7 million and an over-collected deferred energy balance of \$40.0 million, respectively. To address the under- and over-collection of energy costs, we implemented rate changes as follows:

Effective Date of Rate Change	% Change
January 1, 2016	(5.4)
April 1, 2016	(6.8)
September 1, 2016	(6.5)
January 1, 2017	(6.7)
January 1, 2018	11.1

Financial Instruments (including Derivatives)

Investments included in the nuclear decommissioning trust are classified as available for sale, and accordingly, are carried at fair value. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or a regulatory asset, respectively, until realized.

Unrestricted investments and lease deposits in debt securities that we have the positive intent and ability to hold to maturity are classified as held to maturity and are recorded at amortized cost. Non-marketable equity investments in other investments are recorded at cost. Equity securities in other investments are recorded at fair value. See Note 9—Investments.

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of these forward purchase derivative contracts qualify for the normal purchases/normal sales accounting exception under Accounting for Derivatives and Hedging. As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the physically-delivered forward contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for our facilities which utilize natural gas. These derivatives do not qualify for the normal purchases/normal sales accounting exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with Accounting for Derivatives and Hedging. Accordingly, gains and losses on derivative contracts are deferred into other comprehensive income until the hedged underlying transaction occurs or is no longer likely to occur. We do not have any other comprehensive income for the periods presented. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory liability or regulatory asset, respectively, in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense as the power or fuel is delivered and/or the contract settles. There were no contracts for which we have elected cash flow hedge accounting and therefore, there was no hedge ineffectiveness during the years ended December 31, 2017, 2016, and 2015.

Generally, derivatives are reported at fair value on the Consolidated Balance Sheet in the regulatory assets or regulatory liabilities account and deferred charges–other and deferred credits and other liabilities–other. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract’s estimated fair value.

Patronage Capital

We are organized and operate as a cooperative. Patronage capital represents our retained net margins, which have been allocated to our members based upon their respective power purchases in accordance with our bylaws. Any distributions of patronage capital are subject to the discretion of our board of directors and the restrictions contained in our Indenture. See Note 11—Long-term Debt for discussion of the restrictions contained in the Indenture.

We operate on a not-for-profit basis and, accordingly, seek to generate revenues sufficient to recover our cost of service and produce margins sufficient to establish reasonable reserves, meet financial coverage requirements, and accumulate additional equity approved by our board of directors. On November 7, 2017, and December 13, 2016, our board of directors approved an additional equity contribution of $14.1 million and $5.8 million, respectively. Revenues in excess of expenses in any year are designated as net margin attributable to ODEC on our Consolidated Statements of Revenues, Expenses, and Patronage Capital. We designate retained net margins attributable to ODEC on our Consolidated Balance Sheet as patronage capital, which we assign to each of our members on the basis of its class of membership and business with us. On November 7, 2017, and December 13, 2016, our board of directors declared a patronage capital retirement of $14.1 million and $5.8 million, respectively. The $14.1 million patronage capital retirement is to be paid on April 2, 2018. The $5.8 million patronage capital retirement was paid on April 3, 2017. As a result of the November 7, 2017, and December 13, 2016, declarations, we reduced patronage capital and increased accounts payable–members by $14.1 million and $5.8 million, respectively.

Concentrations of Credit Risk

Financial instruments that potentially subject us to concentrations of credit risk consist of cash equivalents, investments, derivatives, and receivables arising from sales to our members and non-members. Concentrations of credit risk with respect to receivables arising from sales to our member distribution cooperatives as reflected by accounts receivable–members were $83.1 million and $85.1 million, as of December 31, 2017 and 2016, respectively.

Segment

We are organized for the purpose of supplying the power our member distribution cooperatives require to serve their customers on a cost-effective basis. Our President and CEO serves as our chief operating decision maker who manages and reviews our operating results as one operating, and therefore one reportable, segment. We supply our member distribution cooperatives' energy and demand requirements through a portfolio of resources including generating facilities, physically-delivered forward power purchase contracts, and spot market energy purchases.

Cash Equivalents

For purposes of our 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.

New Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09 Revenue from Contracts with Customers. This update requires entities to recognize revenue when the transfer of promised goods or services to customers occurs in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. We supply power requirements (energy and demand) to our eleven member distribution cooperatives subject to substantially identical wholesale power contracts with each of them. The revenues from these wholesale power contracts constituted at least 95% of our total revenues for the past three years. We have substantially completed our contract review of our wholesale power and other contracts within the scope of Topic 606, and are finalizing the last steps of our analysis. We currently do not anticipate a significant impact from adopting this standard and will adopt it in the first quarter of 2018.

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

NOTE 2—Electric Plant

Our net electric plant is composed of the following as of December 31, 2017:

	Clover	North Anna	Combustion Turbine Facilities	Wildcat Point	Other	Total
			(in thousands)			
Property, plant, and equipment	$ 698,497	$ 366,423	$ 590,137	$ —	$ 99,179	$1,754,236
Accumulated depreciation	(375,106)	(216,486)	(271,225)	—	(28,884)	(891,701)
Net Property, plant, and equipment	323,391	149,937	318,912	—	70,295	862,535
Nuclear fuel, at amortized cost	—	18,089	—	—	—	18,089
Construction work in progress	6,189	24,982	72	789,661	1,763	822,667
Net Electric Plant	$ 329,580	$ 193,008	$ 318,984	$ 789,661	$ 72,058	$1,703,291

Our net electric plant is composed of the following as of December 31, 2016:

	Clover	North Anna	Combustion Turbine Facilities	Wildcat Point	Other	Total
			(in thousands)			
Property, plant, and equipment	$ 695,843	$ 365,646	$ 589,049	$ —	$ 96,314	$1,746,852
Accumulated depreciation	(364,602)	(206,868)	(257,026)	—	(26,572)	(855,068)
Net Property, plant, and equipment	331,241	158,778	332,023	—	69,742	891,784
Nuclear fuel, at amortized cost	—	22,138	—	—	—	22,138
Construction work in progress	3,927	15,181	62	715,855	1,971	736,996
Net Electric Plant	$ 335,168	$ 196,097	$ 332,085	$ 715,855	$ 71,713	$1,650,918

We hold a 50% undivided ownership interest in Clover, a two-unit, 877 MW (net capacity entitlement) coal-fired electric generating facility operated by Virginia Power, which owns the balance of the plant. We are responsible for and must fund half of all additions and operating costs associated with Clover, as well as half of Virginia Power's administrative and general expenses directly attributable to Clover. Our portion of assets, liabilities, and operating expenses associated with Clover are included on our consolidated financial statements in accordance with proportionate consolidation accounting. As of December 31, 2017 and 2016, we had an outstanding accounts payable balance of $10.4 million and $8.2 million, respectively, due to Virginia Power for operation, maintenance, and capital investment at Clover.

We hold an 11.6% undivided ownership interest in North Anna, a two-unit, 1,892 MW (net capacity entitlement) nuclear power facility operated by Virginia Power, which owns the balance of the plant. We are responsible for and must fund 11.6% of all post-acquisition date additions and operating costs associated with North Anna, as well as a pro-rata portion of Virginia Power's administrative and general expenses directly attributable to North Anna. Our portion of assets, liabilities, and operating expenses associated with North Anna are included on our consolidated financial statements in accordance with proportionate consolidation accounting. As of December 31, 2017 and 2016, we had an outstanding accounts payable balance of $8.8 million and $3.8 million, respectively, due to Virginia Power for operation, maintenance, and capital investment at North Anna.

We own three combustion turbine facilities that are primarily fueled by natural gas. We also own six distributed generation facilities, which are included in "Other" in the net electric plant table. Additionally, we own approximately 110 miles of transmission lines on the Virginia portion of the Delmarva Peninsula included in "Other," as well as two 1,100 foot, 500 kV transmission lines and a 500 kV substation at our combustion turbine site in Maryland included in "Combustion Turbine Facilities."

Wildcat Point

We are the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. Wildcat Point's major equipment consists of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. While the facility was scheduled to become operational in mid-2017, we currently anticipate that Wildcat Point will achieve substantial completion in the spring of 2018. The majority of construction has been completed; however, some additional construction work and testing is required before Wildcat Point becomes commercially operable and available for dispatch by PJM to meet a portion of our member distribution cooperatives' power requirements. WOPC, the EPC contractor, claims that 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 do not believe any liability is estimable or probable and intend to vigorously defend against these claims.

Additionally, on September 29, 2017, we filed a complaint in the 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 December 31, 2017, we capitalized construction costs related to Wildcat Point totaling $789.7 million, including $77.8 million of capitalized interest, offset by $53.2 million of liquidated damages. We do not believe we have any additional liability associated with WOPC's claims; and therefore, we continue to estimate that the total project cost, after consideration of liquidated damages, is consistent with our original project cost estimate of $834.3 million.

NOTE 3—Accounting for Asset Retirement and Environmental Obligations

We account for our asset retirement obligations in accordance with Accounting for Asset Retirement and Environmental Obligations. This requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value when incurred and capitalized as part of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized asset is depreciated over the useful life of the long-lived asset.

In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Our estimated liability could change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

A significant portion of our asset retirement obligations relate to our share of the future costs to decommission North Anna. At December 31, 2017 and 2016, North Anna's nuclear decommissioning asset retirement obligation totaled $105.8 million and $101.6 million, respectively. Approximately every four years, a new decommissioning study for North Anna is performed by third-party experts. A new study was performed in 2014, and we adopted it effective December 1, 2014, which resulted in an additional layer related to the asset retirement obligation associated with North Anna. The additional layer resulted in an increase to our asset retirement cost and our asset retirement obligation of $18.0 million. Increased spent fuel costs, including interim storage, insurance premiums, and regulatory and environmental permits and fees, as a result of the DOE delay for acceptance of spent fuel, are the primary drivers for the increase in the asset retirement obligation. We are not aware of any events that have occurred since the 2014 study that would materially impact our estimate. We are required to maintain a funded trust to satisfy our future obligation to decommission the North Anna facility. See Note 9—Investments.

In 2016, we recorded a $2.9 million decrease to an asset retirement obligation for Clover related to a change in estimate as a result of more refined cost information obtained during the contract bidding process. In 2017, we established a $2.1 million asset retirement obligation related to Wildcat Point and a $0.1 million asset retirement obligation related to one of our distributed generation facilities.

The following represents changes in our asset retirement obligations for the years ended December 31, 2017 and 2016 (in thousands):

Asset retirement obligations as of December 31, 2015	$ 118,200
Accretion expense	4,839
Decrease in asset retirement obligations	(2,869)
Payments	(87)
Asset retirement obligations as of December 31, 2016	$ 120,083
Accretion expense	5,044
Additional asset retirement obligations	2,210
Payments	(867)
Asset retirement obligations as of December 31, 2017	$ 126,470

The cash flow estimates for North Anna's asset retirement obligations are based upon the 20-year life extension which was granted in 2003 and extends the life of Unit 1 to April 1, 2038, and the life of Unit 2 to August 21, 2040. Given the life extension, the nuclear decommissioning trust was, and currently is, estimated to be adequate to fund North Anna's asset retirement obligations and no additional funding was, or is, currently required. We ceased collection of decommissioning expense in August 2003 with the approval of FERC. As we are not currently collecting decommissioning expense in our rates, we are deferring the difference between the earnings on the nuclear decommissioning trust and the total asset retirement obligation related depreciation and accretion expense for North Anna as part of our asset retirement obligation regulatory liability. See Note 10—Regulatory Assets and Liabilities. Virginia Power, the co-owner of North Anna, has announced its intention to apply for an additional 20-year operating license extension for North Anna.

NOTE 4—Power Purchase Agreements

In 2017, 2016, and 2015, our owned generating facilities together furnished approximately 36.7%, 45.2%, and 43.0%, respectively, of our energy requirements. The remaining needs were satisfied through purchases of power in the market from investor owned utilities and power marketers through long-term and short-term physically-delivered forward power purchase contracts. We also purchased power in the spot energy market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy and sales of excess energy. Additionally, we utilize policies, procedures, and various hedging instruments to manage our power market price risks. These policies and procedures, developed in consultation with ACES, an energy trading and risk management company, are designed to strike an appropriate balance between minimizing costs and reducing energy cost volatility. We are required to post collateral from time to time due to changes in power prices. As of December 31, 2017, we had posted $12.0 million in letters of credit and as of December 31, 2016, we had posted $5.0 million in letters of credit.

Our purchased power expense for 2017, 2016, and 2015 was $397.4 million, $408.0 million, and $494.9 million, respectively.

As of December 31, 2017, our capacity and energy purchase obligations under the various agreements were as follows:

Year Ending December 31,	Capacity and Energy Obligations
	(in millions)
2018	$ 203.5
2019	186.8
2020	81.5
	$ 471.8

NOTE 5—Wholesale Power Contracts

Our financial relationships with our member distribution cooperatives are based primarily on our contractual arrangements for the supply of power and related transmission and ancillary services. These arrangements are set forth in our wholesale power contracts with our member distribution cooperatives which are effective until January 1, 2054, and beyond this date unless either party gives the other at least three years notice of termination. The wholesale power contracts are "all-requirements" contracts. Each contract obligates us to sell and deliver to our member distribution cooperative, and obligates our member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so.

An exception to the all-requirements obligations of our member distribution cooperatives relates to the ability of our eight mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from SEPA, a federal power marketing administration. Purchases under this exception constituted less than 2% of our member distribution cooperatives' total energy requirements in 2017.

There are two additional limited exceptions to the all-requirements nature of the contract. One exception 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. The other exception permits our member distribution cooperatives to purchase additional power from other suppliers in limited circumstances following approval by our board of directors.

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 will be 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.

As of December 31, 2017, none of our member distribution cooperatives had utilized the other exception noted above.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formula rate. We review our formula rate design at least every three years to consider whether it is appropriately achieving its intended results. The formula rate, which has been filed with and accepted by FERC, is designed to recover our total cost of service and create a firm equity base. See "Regulation—Rate Regulation" in Item 1, "Legal Proceedings—FERC Proceeding Related to Formula Rate" in Item 3, and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate" in Item 7.

More specifically, the formula rate is intended to meet all of our costs, expenses, and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement, and decommissioning of our generating plants, transmission system, or related facilities, services provided to the member distribution cooperatives, and the acquisition and transmission of power or related services, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);
- any additional cost or expense, imposed or permitted by any regulatory agency; and

- additional amounts necessary to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory, and governmental requirements, which apply to us from time to time.

Revenues from our member distribution cooperatives for the past three years were as follows:

	Year Ended December 31, 2017	2016	2015
	(in millions)		
Rappahannock Electric Cooperative	$ 217.7	$ 271.2	$ 334.2
Shenandoah Valley Electric Cooperative	146.8	164.5	181.0
Delaware Electric Cooperative, Inc.	97.5	105.9	114.0
Choptank Electric Cooperative, Inc.	69.7	77.2	83.8
Southside Electric Cooperative	58.4	67.9	76.5
A&N Electric Cooperative	46.0	51.1	55.5
Mecklenburg Electric Cooperative	36.7	41.2	47.4
Prince George Electric Cooperative	20.6	22.5	25.4
Northern Neck Electric Cooperative	18.2	21.3	23.4
Community Electric Cooperative	11.4	14.4	16.6
BARC Electric Cooperative	8.6	9.9	11.1
Total	$ 731.6	$ 847.1	$ 968.9

NOTE 6—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 December 31, 2017 and 2016:

	December 31, 2017	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Observable Inputs (Level 3)
		(in thousands)		
Nuclear decommissioning trust [(1)]	$ 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	$ —

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

(1) For additional information about our nuclear decommissioning trust, see Note 9—Investments.

(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 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—Summary of Significant Accounting Policies.

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.

NOTE 7 — 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—Summary of Significant Accounting Policies.

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 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 December 31, 2017	As of December 31, 2016
Natural Gas	MMBTU	23,700,000	14,250,000

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

	Balance Sheet Location	Fair Value As of December 31, 2017	Fair Value As of December 31, 2016
		(in thousands)	
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges-other	$ —	$ 6,968
Total derivatives in an asset position		$ —	$ 6,968
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 1,034	$ —
Total derivatives in a liability position		$ 1,034	$ —

The Effect of Derivative Instruments on the Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Years Ended December 31, 2017 and 2016

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of December 31, 2017	2016	Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income	Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Year Ended December 31, 2017	2016
	(in thousands)			(in thousands)	
Natural gas futures contracts	$ (2,008)	$ 7,005	Fuel	$ 1,342	$ (2,369)
Total	$ (2,008)	$ 7,005		$ 1,342	$ (2,369)

NOTE 8—Long-term Lease Transaction

On March 1, 1996, we entered into a long-term lease transaction with an owner trust for the benefit of an investor. Under the terms of the transaction, we entered into a 48.8 year lease of our interest in Clover Unit 1, valued at $315.0 million, to such owner trust, and immediately after we entered into a 21.8 year lease of the interest back from such owner trust. As a result of the transaction, we recorded a deferred gain of $23.7 million, which was amortized into income ratably over the 21.8 year operating lease term, as a reduction to depreciation and amortization expense. As of December 31, 2017, the deferred gain was fully amortized.

We used a portion of the one-time rental payment of $315.0 million we received to enter into a payment undertaking agreement and to purchase an investment that would provide for substantially all of our periodic rent payments under the leaseback, and the fixed purchase price of the interest in the unit at the end of the term of the leaseback if we were to exercise our option to purchase the interest of the owner trust in the unit at that time. As of December 31, 2017, the payment undertaking agreement had a balance of $304.7 million, and the amount of debt considered to be extinguished by in substance defeasance was $304.7 million.

We elected to purchase the owner trust's interest in the unit and terminate the lease effective January 5, 2018, for a fixed purchase price of $430.5 million. On January 5, 2018, payments under the payment undertaking agreement funded $289.7 million of this amount, and $32.2 million was provided by us and in turn paid to us as the holder of a loan to the owner trust. The remaining balance of the fixed purchase price is funded by United States Treasury securities with a maturity value of $108.6 million and will be paid in four installments during 2018.

NOTE 9—Investments

Investments were as follows as of December 31, 2017 and 2016:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses (in thousands)	Fair Value	Carrying Value
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
December 31, 2016						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 44,086	$ 3,537	$ —	$ 47,623	$ 47,623
Equity securities	Available for sale	75,332	35,958	(277)	111,013	111,013
Cash and other	Available for sale	519	—	—	519	519
Total Nuclear Decommissioning Trust		$ 119,937	$ 39,495	$ (277)	$ 159,155	$ 159,155
Lease Deposits [2]						
Government obligations	Held to maturity	$ 104,514	$ 2,948	$ —	$ 107,462	$ 104,514
Total Lease Deposits		$ 104,514	$ 2,948	$ —	$ 107,462	$ 104,514
Unrestricted investments						
Government obligations	Held to maturity	$ 2,000	$ 1	$ -	$ 2,001	$ 2,000
Debt securities	Held to maturity	2,210	6	-	2,216	2,210
Total Unrestricted Investments		$ 4,210	$ 7	$ -	$ 4,217	$ 4,210
Other						
Equity securities	Trading	$ 198	$ 49	$ —	$ 247	$ 247
Non-marketable equity investments	Equity	2,142	2,012	—	4,154	2,142
Total Other		$ 2,340	$ 2,061	$ —	$ 4,401	$ 2,389
						$ 270,268

(1) Investments in the nuclear decommissioning trust are restricted for the use of funding our share of the asset retirement obligations of the future decommissioning of North Anna. See Note 3—Accounting for Asset Retirement and Environmental Obligations. 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—Long-term Lease Transaction.

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

Description	December 31, 2017 Cost	December 31, 2017 Carrying Value	December 31, 2016 Cost	December 31, 2016 Carrying Value
	(in thousands)		(in thousands)	
Available for sale	$ 132,532	$ 183,681	$ 119,937	$ 159,155
Held to maturity	111,373	111,373	108,724	108,724
Equity	2,140	2,140	2,142	2,142
Trading	223	308	198	247
Total	$ 246,268	$ 297,502	$ 231,001	$ 270,268

Contractual maturities of debt securities as of December 31, 2017, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Available for sale (1)	$ —	$ —	$ 59,404	$ —	$ 59,404
Held to maturity	111,018	355	—	—	111,373
Total	$ 111,018	$ 355	$ 59,404	$ —	$ 170,777

(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.

NOTE 10—Regulatory Assets and Liabilities

In accordance with Accounting for Regulated Operations, we record regulatory assets and liabilities that result from our ratemaking. Our regulatory assets and liabilities as of December 31, 2017 and 2016, were as follows:

	December 31, 2017	December 31, 2016
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	$ 9,977	$ 11,841
Deferred asset retirement costs	296	313
NOVEC contract termination fee	26,915	29,362
Loan acquisition fee	—	224
Interest rate hedge	2,220	2,381
Voluntary prepayment to NRECA Retirement Security Plan	3,868	4,641
Deferred net unrealized losses on derivative instruments	2,008	—
Wildcat Point lease termination	—	920
Total Regulatory Assets	$ 45,284	$ 49,682
Regulatory Assets included in Current Assets:		
Deferred energy	$ 3,669	$ —
Regulatory Liabilities:		
North Anna asset retirement obligation deferral	$ 49,739	$ 42,390
North Anna nuclear decommissioning trust unrealized gain	51,149	39,218
Unamortized gains on reacquired debt	349	407
Deferred net unrealized gains on derivative instruments	—	7,005
Total Regulatory Liabilities	$ 101,237	$ 89,020
Regulatory Liabilities included in Current Liabilities:		
Deferred energy	$ —	$ 40,029
Regulatory liability-revenue deferral	$ 15,000	$ —

The regulatory assets will be recognized as expenses concurrent with their recovery through rates and the regulatory liabilities will be recognized as reductions to expenses concurrent with their return through rates.

Regulatory assets included in deferred charges are detailed as follows:

- Unamortized losses on reacquired debt are the costs we incurred to purchase our outstanding indebtedness prior to its scheduled retirement. These losses are amortized over the life of the original indebtedness and will be fully amortized in 2023.
- Deferred asset retirement costs reflect the cumulative effect of a change in accounting principle for the Clover and distributed generation facilities as a result of the adoption of Accounting for Asset Retirement and Environmental Obligations. These costs will be fully amortized in 2034.
- NOVEC contract termination fee reflects the amount allocated to the contract value of the payment to NOVEC in 2008 as part of the termination agreement. The wholesale power contract with NOVEC was scheduled to expire in 2028, thus the contract termination fee will be amortized ratably through 2028 through amortization of regulatory asset/(liability), net.
- Loan acquisition fee reflects the one-time fee we paid to the investor to facilitate the acquisition of the $33.0 million loan related to the lease of Clover Unit 1. This fee was amortized ratably over the remaining life of the lease and was fully amortized as of December 31, 2017.

- Interest rate hedge. To mitigate a portion of our exposure to fluctuations in long-term interest rates related to the debt we issued in 2011, we entered into an interest rate hedge. This will be amortized over the life of the 2011 debt and will be fully amortized in 2050.
- Voluntary prepayment to NRECA Retirement Security Plan. In April 2013, we elected to make a voluntary prepayment of $7.7 million to the NRECA Retirement Security Plan, a noncontributory, defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. It is considered a multi-employer plan under the accounting standards. We recorded this prepayment as a regulatory asset which will be fully amortized in 2022. See Note 13—Employee Benefits.
- Deferred net unrealized losses on derivative instruments will be matched and recognized in the same period the expense is incurred for the hedged item.
- Wildcat Point lease termination. We had a ground lease related to land and land rights associated with Wildcat Point that was accounted for as an operating lease. In 2015, we purchased the land and the land rights from Essential Power Rock Springs, LLC for $40.0 million. Prior to purchasing the land and land rights, thus terminating the ground lease, we made prepaid rent payments related to the ground lease. We established a regulatory asset for the unamortized portion of the prepaid rent which was fully amortized as of May 31, 2017.

Regulatory assets included in current assets are detailed as follows:

- Deferred energy balance represents the net accumulation of under-collection of energy costs. We use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Under-collected deferred energy balances are collected from our member distribution cooperatives in subsequent periods.

Regulatory liabilities included in deferred credits and other liabilities are detailed as follows:

- North Anna asset retirement obligation deferral is the cumulative effect of change in accounting principle as a result of the adoption of Accounting for Asset Retirement and Environmental Obligations plus the deferral of subsequent activity primarily related to accretion expense offset by interest income on the nuclear decommissioning trust.
- North Anna nuclear decommissioning trust unrealized gain reflects the unrealized gain on the investments in the nuclear decommissioning trust.
- Unamortized gains on reacquired debt are the gains we recognized when we purchased our outstanding indebtedness prior to its scheduled retirement. These gains are amortized over the life of the original indebtedness and will be fully amortized in 2023.
- Deferred net unrealized gains on derivative instruments will be matched and recognized in the same period the expense is incurred for the hedged item.

Regulatory liabilities included in current liabilities are detailed as follows:

- Deferred energy balance represents the net accumulation of over-collection of energy costs. We use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Over-collected deferred energy balances are credited to our member distribution cooperatives in subsequent periods.
- Regulatory liability-revenue deferral to be amortized ratably in 2018 to reduce revenue requirements.

NOTE 11—Long-term Debt

Long-term debt consists of the following:

	December 31, 2017	December 31, 2016
	(in thousands)	
$250,000,000 principal amount of First Mortgage Bonds, 2017 Series A due 2037 at an interest rate of 3.33%	$ 250,000	$ —
$260,000,000 principal amount of First Mortgage Bonds, 2015 Series A due 2044 at an interest rate of 4.46%	260,000	260,000
$72,000,000 principal amount of First Mortgage Bonds, 2015 Series B due 2053 at an interest rate of 4.56%	72,000	72,000
$50,000,000 principal amount of First Mortgage Bonds, 2013 Series A due 2043 at an interest rate of 4.21%	50,000	50,000
$50,000,000 principal amount of First Mortgage Bonds, 2013 Series B due 2053 at an interest rate of 4.36%	50,000	50,000
$90,000,000 principal amount of First Mortgage Bonds, 2011 Series A due 2040 at an interest rate of 4.83%	69,000	72,000
$165,000,000 principal amount of First Mortgage Bonds, 2011 Series B due 2040 at an interest rate of 5.54%	165,000	165,000
$95,000,000 principal amount of First Mortgage Bonds, 2011 Series C due 2050 at an interest rate of 5.54%	78,375	80,750
$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	114,579	124,996
$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	137,500	150,000
	1,246,454	1,024,746
Debt issuance costs	(7,266)	(6,371)
Current maturities	(40,792)	(28,292)
	$ 1,198,396	$ 990,083

As of December 31, 2017 and 2016, deferred gains and losses on reacquired debt totaled a net loss of approximately $9.6 million and $11.4 million, respectively. Deferred gains and losses on reacquired debt are deferred under regulatory accounting. See Note 10—Regulatory Assets and Liabilities.

Maturities of long-term debt for the next five years and thereafter are as follows:

Year Ending December 31,	(in thousands)
2018	$ 40,792
2019	40,792
2020	40,792
2021	49,041
2022	49,041
2023 and thereafter	1,025,996
	$ 1,246,454

The aggregate fair value of long-term debt was $1,320.1 million and $1,092.0 million as of December 31, 2017 and 2016, respectively, based on current market prices. For debt issues that are not quoted on an exchange, interest rates currently available to us for issuance of debt with similar terms and remaining maturities are used to estimate fair value.

All of our long-term debt is secured under our Indenture. Substantially all of our real property and tangible personal property and some of our intangible personal property are pledged as collateral under the Indenture. Under the Indenture, we may not make any distribution, including a dividend or payment or retirement of patronage capital, to our members if an event of default exists under the Indenture. Otherwise, we may make a distribution to our members if (1) after the distribution, our patronage capital as of the end of the most recent fiscal quarter would be equal to or greater than 20% of our total long-term debt and patronage capital, or (2) all of our distributions for the year in which the distribution is to be made do not exceed 5% of the patronage capital as of the end of the most recent fiscal year. For this purpose, patronage capital and total long-term debt do not include any earnings retained in any of our subsidiaries or affiliates or the debt of any of our subsidiaries or affiliates.

On July 6, 2017, we issued $250 million of long-term debt in a private placement transaction. The issuance consisted of $250 million of 3.33% First Mortgage Bonds, 2017 Series A due December 1, 2037.

Additionally, we maintain a revolving credit facility. See Note 12—Liquidity Resources.

NOTE 12—Liquidity Resources

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 December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings at a weighted average interest rate of 2.6% and $12.0 million in letters of credit. As of December 31, 2016, we had outstanding under this facility, $152.0 million in borrowings at a weighted average interest rate of 1.6% and $5.2 million in letters of credit.

Borrowings under the credit agreement that are based on Eurodollar rates bear interest at LIBOR plus a margin ranging from 0.90% to 1.5%, depending on our credit ratings. Borrowings not based on Eurodollar rates, including swingline borrowings, bear interest at the highest of (1) the federal funds effective rate plus 0.5%, (2) the prime commercial lending rate of the administrative agent, and (3) the daily LIBOR for a one-month interest period plus 1.0% , plus in each case a margin ranging from 0.0% to 0.5%. Additionally, we are also responsible for customary unused commitment fees, an administrative agent fee and letter of credit fees.

The credit agreement contains customary conditions to borrowing or the issuance of letters of credit, representations and warranties, and covenants. The credit agreement obligates us to maintain a debt to capitalization ratio of no more than 0.85 to 1.00 and to maintain a margins for interest ratio of no less than 1.10 times interest charges (calculated in accordance with our Indenture). Obligations under the credit agreement may be accelerated following, among other things:

- our failure to timely pay any principal and interest due under the credit facility;
- a breach by us of our representations and warranties in the credit agreement or related documents;
- a breach of a covenant contained in the credit agreement, which, in some cases we are given an opportunity to cure and, in certain cases, includes a debt to capitalization financial covenant;
- failure to pay, when due, other indebtedness above a specified amount;
- an unsatisfied judgment above specified amounts;
- bankruptcy or insolvency events relating to us;
- invalidity of the credit agreement and related loan documentation or our assertion of invalidity; and
- a failure by our member distribution cooperatives to pay amounts in excess of an agreed threshold owing to us beyond a specified cure period.

We are in compliance with the credit agreement.

We maintain a program which allows our member distribution cooperatives to prepay or extend payment on their monthly power bills. Under this program, we pay interest on prepayment balances at a blended investment and short-term borrowing rate, and we charge interest on extended payment balances at a blended prepayment and short-term borrowing rate. Amounts prepaid by our member distribution cooperatives are included in accounts payable–members and as of December 31, 2017 and 2016, were $10.8 million and $45.5 million, respectively. Amounts extended to our member distribution cooperatives are included in accounts receivable–members and as of December 31, 2017 and 2016, were $7.2 million and $9.2 million, respectively.

NOTE 13—Employee Benefits

Substantially all of our employees participate in the NRECA Retirement Security Plan, a noncontributory, defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the IRC. It is considered a multi-employer plan under the accounting standards. The legal name of the plan is the NRECA Retirement Security Plan; the employer identification number is 53–0116145, and the plan number is 333. Plan information is available publicly through the annual Form 5500, including attachments. The plan year is January 1 through December 31. In total, the NRECA Retirement Security Plan was over 80% funded on January 1, 2017 and 2016, based on the PPA funding target and PPA actuarial value of assets on those dates. The cost of the plan is funded annually by payments to NRECA to ensure that annuities in amounts established by the plan will be available to individual participants upon their retirement. We also participate in the Deferred Compensation Pension Restoration Plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the Retirement Security Plan because of the IRC limitations. Our required contribution to the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan totaled $3.2 million, $2.7 million, and $2.5 million in 2017, 2016, and 2015, respectively. In each of these years, our contributions represented less than 5% of the total contributions made to the plan by all participating employers. In 2013, we elected to make a voluntary prepayment of $7.7 million to the NRECA Retirement Security Plan and recorded this payment as a regulatory asset which will be fully amortized in 2022. There has been no funding improvement plan or rehabilitation plan implemented nor is one pending, and we did not pay a surcharge to the plan for 2017. Pension expense, inclusive of administrative fees, was $4.1 million, $3.6 million, and $3.4 million for 2017, 2016, and 2015, respectively. Pension expense for 2017, 2016, and 2015 includes $0.8 million related to the amortization of the voluntary prepayment regulatory asset.

We have also elected to participate in a defined contribution 401(k) retirement plan administered by TransAmerica Retirement Solutions. We match up to the first 2% of each participant’s base salary. Our matching contributions were $289,000, $240,000, and $231,000 in 2017, 2016, and 2015, respectively.

NOTE 14—Supplemental Cash Flows Information

Cash paid for interest, net of amounts capitalized, in 2017, 2016, and 2015, was $23.8 million, $26.4 million, and $42.0 million, respectively. Cash paid for income taxes was immaterial in 2017, 2016, and 2015. Accrued capital expenditures in 2017, 2016, and 2015 were $23.1 million, $66.9 million, and $74.8 million, respectively.

NOTE 15—Commitments and Contingencies

Environmental

We are subject to federal, state, and local laws and regulations and permits designed to both protect human health and the environment and to regulate the emission, discharge, or release of pollutants into the environment. We believe we are in material compliance with all current requirements of such environmental laws and regulations and permits. However, as with all electric utilities, the operation of our generating units could be affected by future changes in environmental laws and regulations, including new requirements. Capital expenditures and increased operating costs required to comply with any future regulations could be significant.

Insurance

The Price-Anderson Amendments Act of 1988 provides the public up to $13.4 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and is subject to change every five years for inflation and for the number of licensed reactors. Owners of nuclear facilities could be assessed up to $127 million for each of their licensed reactors not to exceed $19 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. Virginia Power, the co-owner of North Anna, is responsible for operating North Anna. Under several of the nuclear insurance policies procured by Virginia Power to which we are a party, we are subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance companies.

As a joint owner of North Anna, we are a party to the insurance policies that Virginia Power procures to limit the risk of loss associated with a possible nuclear incident at the station, as well as policies regarding general liability and property coverage. All policies are administered by Virginia Power, which charges us for our proportionate share of the costs.

Our share of the maximum retrospective premium assessments for the coverage assessments described above is estimated to be a maximum of $33.4 million at December 31, 2017.

NOTE 16—SUBSEQUENT EVENT

On March 13, 2018, our Board of Directors approved an increase to our total energy rate of approximately 3.7%, effective April 1, 2018. This increase was implemented due to changes in our realized as well as projected energy costs.

NOTE 17—Selected Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years 2017 and 2016 follows. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for the interim periods may fluctuate as a result of weather conditions, changes in rates, and other factors.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(in thousands)		
Statement of Operations Data					
2017					
Operating Revenues	$ 189,779	$ 156,907	$ 193,425	$ 212,996	$ 753,107
Operating Margin	8,641	(836)	9,813	22,356	39,974
Net Margin attributable to ODEC [1]	2,968	3,047	3,258	17,354	26,627
2016					
Operating Revenues	$ 256,459	$ 199,149	$ 222,802	$ 199,461	$ 877,871
Operating Margin	12,224	9,884	9,022	14,062	45,192
Net Margin attributable to ODEC [2]	2,953	2,955	2,991	8,738	17,637

(1) For the fourth quarter of 2017, includes an equity contribution of $14.1 million.
(2) For the fourth quarter of 2016, includes an equity contribution of $5.8 million.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Effectiveness of Disclosure Controls and Procedures

As of the end of the period covered by this report, our management, including the Interim President and CEO, who also is our Senior Vice President and CFO, conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the Interim President and CEO, who also is our Senior Vice President and CFO, 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 manner. We have established a Disclosure Assessment Committee composed of members of our senior and middle management to assist in this evaluation. No significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls have occurred during the previous fiscal year.

Management's Annual Report on Internal Control over Financial Reporting

Our management has assessed our internal control over financial reporting as of December 31, 2017, based on criteria for effective internal control over financial reporting described in "2013 Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that as of December 31, 2017, our system of internal control over financial reporting was properly designed and operating effectively based upon the specified criteria. We have not identified any material weaknesses in our internal control over financial reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is composed of policies, procedures, and reports designed to provide reasonable assurance to our management and board of directors that the financial reporting and the preparation of the financial statements for external reporting purposes has been handled in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes those policies and procedures that (1) govern records to accurately and fairly reflect the transactions and dispositions of assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable safeguards against or timely detection of material unauthorized acquisition, use or disposition of our assets.

Changes in Internal Control over Financial Reporting

No material changes in our internal controls over financial reporting or in other factors that could significantly affect such controls have occurred during the past fiscal year.

Inherent Limitations on Internal Control

Inherent limitations exist with respect to the effectiveness of any system of internal control over financial reporting. No control system can provide absolute assurance that all control issues and instances of error or fraud, if any, have been detected. Even the best designed system can only provide reasonable assurance that the objectives of the control system have been met. Because of these inherent limitations, our internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections as to the effectiveness of internal control in future periods are subject to the risk that internal control may not continue to operate at its current effectiveness levels due to changes in personnel or in our operating environment.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

We are governed by a board of 23 directors, consisting of two representatives from each of our member distribution cooperatives and one representative from TEC. Pursuant to our bylaws, each of our eleven member distribution cooperatives, in good standing, may recommend candidates that meet director qualifications to the nominating committee of our board of directors. At the annual meeting of the members, the nominating committee nominates candidates for election to our board of directors. At least one candidate from each member distribution cooperative must be a director of that member distribution cooperative. Currently and historically, the other candidate from each member distribution cooperative is the chief executive officer of that member distribution cooperative. The candidates for director are elected to our board of directors by a majority vote of the voting delegates from our members. Each member has one voting delegate. We do not control who the member distribution cooperative recommends to the nominating committee. As a result, our board of directors has not developed criteria for the composition of our board, such as diversity, for use in identifying nominees to our board of directors. One director currently serves as a director on behalf of a member distribution cooperative and TEC. Each elected candidate is authorized to represent that member for a renewable term of one year. Our board of directors sets policy and provides direction to our President and CEO. Our board of directors meets approximately 11 times each year.

Information concerning those serving on our board of directors as of December 31, 2017, including principal occupation and employment during the past five years, qualifications, and directorships in public corporations, if any, is listed below.

J. William Andrew, Jr. (64). President and CEO of Delaware Electric Cooperative, Inc. since 2005. Mr. Andrew has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2005.

Paul H. Brown (72). Retired, formerly Vice President of Commercial Lending of Bank of Southside Virginia where he served from 1995 to 2012. Mr. Brown has been a director of ODEC since 2013 and a director of Prince George Electric Cooperative since 2007.

John J. Burke, Jr. (61). Associate broker of Gunther McClary Real Estate since 2004. Mr. Burke has been a director of ODEC since 2016 and a director of Choptank Electric Cooperative, Inc. since 2010.

Darlene H. Carpenter (71). Realtor with Century 21 New Millennium since 2013. Ms. Carpenter was a Realtor with Montague, Miller & Company Realtors, Inc. from 2006 to 2013. Ms. Carpenter has been a director of ODEC since 2009 and a director of Rappahannock Electric Cooperative since 1984.

Earl C. Currin, Jr. (74). Retired, formerly Provost at Southside Community College where he served from 1970 to 2007. Dr. Currin taught both accounting and economics at the college level. Dr. Currin has been a director of ODEC since 2008 and a director of Southside Electric Cooperative since 1986.

E. Garrison Drummond (66). Insurance agent of Drummond Insurance Agency, Inc. since 1984. Mr. Drummond has been a director of ODEC since 2012 and a director of A&N Electric Cooperative since 2002.

Jeffrey S. Edwards (54). President and CEO of Southside Electric Cooperative since 2007. Mr. Edwards has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2007.

Kent D. Farmer (60). President and CEO of Rappahannock Electric Cooperative since 2004. Mr. Farmer has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2004.

Chad N. Fowler (39). Operations manager of Roger Fowler Sales and Service since 2000. Mr. Fowler has been a director of ODEC since 2016 and a director of Community Electric Cooperative since 2007.

Fred C. Garber (73). Retired, formerly President of Mt. Jackson Farm Service from 1973 to 2003. Mr. Garber has been a director of ODEC since 2005 and a director of Shenandoah Valley Electric Cooperative since 1984.

Hunter R. Greenlaw, Jr. (72). President of G.L.M.G. General Contractors, a real estate development and general contracting company since 1974. Mr. Greenlaw has been a director of ODEC since 1991 and a director of Northern Neck Electric Cooperative since 1979.

Steven A. Harmon (56). President and CEO of Community Electric Cooperative since 2013. Mr. Harmon was President and CEO of H-2 Business Solutions, LLC, from 2012 to 2013. Mr. Harmon has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2013.

Michael W. Hastings (57). President and CEO of Shenandoah Valley Electric Cooperative since 2016. Mr. Hastings was President and CEO of Jo-Carroll Energy, Inc. from 2005 to 2016. Mr. Hastings has been a director of ODEC since 2016.

Bruce A. Henry (72). Owner and Secretary/Treasurer of Delmarva Builders, Inc. since 1981. Mr. Henry has been a director of ODEC since 1993 and a director of Delaware Electric Cooperative, Inc. since 1978.

David J. Jones (69). Owner/operator of Big Fork Farms since 1970 and Vice President of Exchange Warehouse, Inc. from 1996 to 2006. Mr. Jones has been a director of ODEC since 1986 and a director of Mecklenburg Electric Cooperative since 1982.

Michael J. Keyser (41). CEO and General Manager of BARC Electric Cooperative since 2010. Mr. Keyser has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2010.

John C. Lee, Jr. (57). President and CEO of Mecklenburg Electric Cooperative since 2008. Mr. Lee has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2008.

Micheal E. Malandro (41). President and CEO of Prince George Electric Cooperative since 2015. Mr. Malandro was Vice President of Engineering of Prince George Electric Cooperative from 2004 to 2015. Mr. Malandro has been a director of ODEC since 2015.

Keith L. Swisher (63). Owner/operator of Swisher Valley Farms, LLC since 1976. Mr. Swisher has been a director of ODEC since 2008 and a director of BARC Electric Cooperative since 1981.

Michael I. Wheatley (62). President and CEO of Choptank Electric Cooperative, Inc. since 2011. Mr. Wheatley has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2011.

Gregory W. White (65). President and CEO of Northern Neck Electric Cooperative since 2005. Mr. White has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2005.

Belvin Williamson, Jr. (54). President and CEO of A&N Electric Cooperative since 2016. Mr. Williamson was Director-Energy Services/Key Accounts for Rappahannock Electric Cooperative from 1998 to 2016. Mr. Williamson has been a director of ODEC since 2016.

Audit Committee Financial Expert

We do not have an audit committee financial expert because of our cooperative governance structure and the resulting experience all of our directors have with matters affecting electric cooperatives in their roles as a chief executive officer or director of one of our member distribution cooperatives. In addition, the audit committee employs the services of accounting and financial consultants as it deems necessary.

Executive Officers

Our President and CEO administers our day-to-day business and affairs. Our executive officers as of December 31, 2017, their respective ages, positions and relevant business experience are listed below.

Jackson E. Reasor (65). President and CEO of ODEC since 1998.

Robert L. Kees (65). Senior Vice President and CFO since 2006. Mr. Kees joined ODEC in 1991 and has held various accounting positions, including Vice President and Controller.

D. Richard Beam (60). Senior Vice President of Power Supply since November 2013. Mr. Beam joined ODEC in 1987 and has held various power supply positions, including Vice President of Power Supply and Transmission Planning from July 2004 to March 2013 and Vice President of Power Supply from April 2013 to November 2013.

On July 24, 2017, Mr. Reasor announced his retirement as President and CEO of ODEC effective January 15, 2018. On November 7, 2017, our board of directors approved the appointment of Mr. Kees to serve as Interim President and CEO effective January 16, 2018, following Mr. Reasor's retirement. Mr. Kees continues to serve as Senior Vice President and CFO. On February 23, 2018, we announced the appointment of Mr. Marcus M. Harris as President and CEO, effective April 2, 2018. Mr. Kees will serve as Interim President and CEO until April 2, 2018.

Code of Ethics

We have a code of ethics which applies to all of our employees, including our President and CEO, Senior Vice President and CFO, and Vice President and Controller. A copy of our code of ethics is available without charge by sending a written request to ODEC, Attention: Mr. Bryan S. Rogers, Vice President and Controller, 4201 Dominion Boulevard, Glen Allen, VA 23060.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

General Philosophy

Our compensation philosophy has four objectives:

- attract and retain a qualified, diverse workforce through a competitive compensation program;
- provide equitable and fair compensation;
- support our business strategy; and
- ensure compliance with applicable laws and regulations.

Total Compensation Package

We compensate our President and CEO and other executive officers through the use of a total compensation package which includes base salary, competitive benefits, and the potential of a bonus. Our President and CEO's base salary is derived from salary data provided by third parties through national compensation surveys. The national compensation survey data includes data from the labor market for positions with similar responsibilities.

Targeted Overall Compensation

Our compensation program utilizes detailed job descriptions for all of our employees including executive officers, with the exception of the President and CEO, as an instrument to establish benchmarked positions. The market compensation information for each position is derived from salary data provided by third parties through national compensation surveys and includes salary data for positions within the determined competitive labor market. Our job descriptions are reviewed annually and include job responsibilities, required knowledge, skills and abilities, and formal education and experience necessary to accomplish the requirements of the position which in turn helps us achieve operational goals. Utilizing this information, our human resources department determines a market-based salary for each position based upon salary survey data provided by third parties. A third-party consultant, Burton-Fuller Management, reviews the market-based salary data we compiled for reasonableness annually. We have defined market-based salary as approximately the 50^{th} percentile of the market. Another third-party consultant, Intandem LLC, has been engaged to create a performance appraisal instrument for the President and CEO position as well as to design, distribute, and compile market valuation models and reports for the executive officers.

Process

We have a committee of our board of directors, the executive committee, which recommends all compensation for our President and CEO to the entire board of directors. The entire board of directors then approves the compensation arrangements for the President and CEO. Our board of directors has delegated to our President and CEO the authority to establish and adjust compensation for all employees other than himself. The compensation for all other employees, including executive officers other than the President and CEO, is approved by our President and CEO based upon market-based salary data. On an annual basis our board of directors reviews the performance and compensation of our President and CEO, and our President and CEO reviews the performance and compensation of the remaining executive officers.

Base Salaries

We are an electric cooperative and do not have any stock and as a result, we do not have equity-based compensation programs. For this reason, substantially all of our compensation to our executive officers is provided in the form of base salary. We want to provide our executive officers with a level of assured cash compensation in the form of base salary that is commensurate with the duties and responsibilities of their positions. These salaries are determined based on market data for positions with similar responsibilities.

Bonuses

Our practice has been to, on infrequent occasions, award cash bonuses related to a specific event, such as the consummation of a significant transaction. At the discretion of our board of directors, a bonus may be awarded to our President and CEO. At the discretion of our President and CEO, bonuses may be awarded to the other executive officers.

Other Benefits

We believe that companies should provide reasonable severance benefits to the President and CEO. In certain circumstances, we may provide severance benefits to other executive officers. On July 24, 2017, Mr. Reasor announced his retirement as President and CEO of ODEC effective January 15, 2018. In connection with Mr. Reasor's retirement, on July 24, 2017, ODEC entered into an amendment of Mr. Reasor's employment agreement to provide for certain retirement benefits. On April 7, 2017, Ms. Ecker and ODEC entered into a separation agreement to set forth their agreement regarding the terms of Ms. Ecker's retirement and end of employment and certain separation payments. See "Potential Payments upon Termination or Change in Control" and "Employment Agreement" below for more information about these arrangements. None of our other executive officers, including our Interim President and CEO, have any contractual severance or termination benefits other than what is provided for under the retirement plans in which they participate.

Plans

Retirement Plans

We participate in the NRECA Retirement Security Plan, a noncontributory, defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. This plan is available to all employees, with limited exceptions, who work at least 1,000 hours per year. It is considered a multi-employer plan under the accounting standards. Benefits, which accrue under the plan, are based upon the employee's base annual salary as of November of the previous year.

We also have a 401(k) plan which is available to all employees in regular positions. Under the 401(k) plan for 2017, employees may have elected to have up to 100% or $18,000, whichever is less, of their salary withheld on a pre-tax basis, subject to Internal Revenue Service limitations, and invested on their behalf. We match up to the first 2% of each participant's base salary. Also, a catch-up contribution is available for participants in the plan once they attain age 50. The maximum catch-up contribution for 2017 was $6,000.

In addition, we have a non-qualified executive deferred compensation plan (the "Deferred Compensation Plan"). Our board of directors, at its discretion, determines who may participate in the plan as well as an annual contribution, if any, up to the maximum amount allowed by IRC regulations. Currently, our board of directors has determined that our President and CEO is the only participant in this plan. We made a $15,000 contribution to the plan each year for his benefit from the inception of the plan in 2006 through 2017.

Pension Restoration Plan

We participate in the Deferred Compensation Pension Restoration Plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit because of IRC limitations. Our President and CEO, Senior Vice President and CFO, and Senior Vice President of Power Supply are the only current participants in this plan.

Perquisites and Other Benefits

Our board of directors reviews the perquisites that our President and CEO receives during contract discussions with our President and CEO. Mr. Reasor was entitled to personal use of a company automobile which amounted to $5,043 in 2017.

The executive officers participate in our other benefit plans on the same terms as other employees. These plans include the defined benefit pension plan, the 401(k) plan, medical insurance, life insurance and accidental death and dismemberment, long-term disability, medical reimbursement and dependent care flexible spending accounts, health savings account, health club membership, vacation, holiday, and sick leave. Relocation benefits are reimbursed for all employees who transfer to another location at the request or convenience of ODEC in accordance with our relocation policy. We believe these benefits are customary for similar employers.

Change in Control

There is no provision in our President and CEO's employment agreement or any other arrangements with any other executive officers that increases or decreases any amounts payable to him or her as a result of a change in control.

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our executive officers for services rendered to us in all capacities during each of the last three fiscal years. The table also identifies the principal capacity in which each of these executives serves.

SUMMARY COMPENSATION

Name and Principal Position	Year	Salary	Bonus	Change in Pension Value and Non-qualified Deferred Compensation Earnings [1][2]	All Other Compen-sation [2]	Total
Jackson E. Reasor	2017	$ 605,062	$ —	$ 74,205	$ 28,731	$ 707,998
President and CEO	2016	592,771	—	70,905	26,272	689,948
	2015	554,565	—	61,882	29,767	646,214
Robert L. Kees	2017 [3]	309,130	—	74,258	7,320	390,708
Senior Vice President and CFO	2016	300,132	—	70,752	7,220	378,104
	2015 [3]	294,944	—	68,071	7,084	370,099
D. Richard Beam	2017 [4]	309,699	—	390,164	7,320	707,183
Senior Vice President of Power Supply	2016	300,687	—	291,263	7,220	599,170
	2015	291,929	—	366,581	7,065	665,575
Elissa M. Ecker [5]	2017 [6]	89,861	—	71,153	213,483	374,497
Vice President of Human Resources	2016	204,893	—	68,618	5,400	278,911
	2015 [6]	201,656	—	103,956	5,178	310,790

(1) The values disclosed here represent the changes in the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan.

(2) The items included in All Other Compensation are identified in the All Other Compensation table below. The Change in Pension Value and Non-Qualified Deferred Compensation Earnings column above and the Present Value of Accumulated Benefit in the Pension Benefits table below disclose the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan benefits for each named executive officer.

(3) For 2017 and 2015, Mr. Kees' salary includes a lump sum payment of $446 and $3,554, respectively. Lump sum payments are not included in the calculation of pension benefits.

(4) For 2017, Mr. Beam's salary includes a lump sum payment of $1,184, which is not included in the calculation of pension benefits.

(5) Ms. Ecker retired from ODEC effective April 15, 2017 and, pursuant to her entering into a separation agreement, received a $210,468 separation payment, less applicable withholding taxes, and is entitled to 12 months of ODEC paid medical insurance premiums valued at $21,487, in the aggregate. Ms. Ecker also received $24,286 for unused vacation. The separation payments are represented in the "All Other Compensation" column and the unused vacation is represented in the "Salary" column.

(6) For 2017 and 2015, Ms. Ecker's salary includes a lump sum payment of $4,189 and $3,692, respectively. Lump sum payments are not included in the calculation of pension benefits.

The following table sets forth information concerning all other compensation awarded to, earned by, or paid to our executive officers during 2017.

ALL OTHER COMPENSATION

Name	Matching Contributions under 401(k) Compensation Plan (1)	Contributions under Deferred Compensation Plan (2)	Perquisites (2)	Cash Separation Payments	Company-paid Life Insurance	Total All Other Compensation
Jackson E. Reasor	$ 5,400	$ 15,000	$ 5,043	$ —	$ 3,288	$ 28,731
Robert L. Kees	5,400	—	—	—	1,920	7,320
D. Richard Beam	5,400	—	—	—	1,920	7,320
Elissa M. Ecker (3)	1,713	—	—	210,468	1,302	213,483

(1) Includes contributions made by us to the 401(k) plan.

(2) For Mr. Reasor, includes $15,000 company contribution to the non-qualified deferred compensation plan and $5,043 for personal use of a company automobile.

(3) Ms. Ecker retired from ODEC effective April 15, 2017, and pursuant to her separation agreement, received a $210,468 separation payment and is entitled to 12 months of ODEC paid medical insurance premiums, valued at $21,487 in the aggregate.

Potential Payments upon Termination or Change in Control

Except for Mr. Reasor, none of our executive officers have any contractual termination benefits other than as provided under the retirement plans in which they participate and none of our executive officers have any change in control benefits.

Employment Agreement

We have an employment agreement with our President and CEO. We do not have an employment agreement with any of our other executive officers or our Vice President and Controller.

On July 24, 2017, Mr. Reasor announced his retirement as President and CEO of ODEC effective January 15, 2018, and we entered into an amendment of Mr. Reasor's June 1, 2016 employment agreement. Under the amendment, we will pay Mr. Reasor compensation at the rate in effect on the date of retirement for one year, plus medical insurance premiums, with limited exceptions, and will transfer ownership of the company automobile used by Mr. Reasor. The amendment also updates the agreement to provide that the last day of the term of Mr. Reasor's employment will be January 15, 2018. The amendment further modifies provisions associated with the appointment of certain senior officers in some circumstances, deletes a non-competition covenant, and adds a non-solicitation covenant relating to employees of ODEC.

Based upon Mr. Reasor's retirement date of January 15, 2018, the benefits he will receive are as follows*:

Annual compensation	$ 614,462
Targeted bonus	—
Unused vacation pay	74,293
Medical insurance	21,568
Total	$ 710,323

*Mr. Reasor would also have been entitled to such benefits under the terms of his amended employment agreement if he was terminated for cause or resigned for good reason on December 31, 2017.

On April 7, 2017, Ms. Ecker and ODEC entered into a separation agreement to set forth their agreement regarding the terms of Ms. Ecker's retirement and end of employment. The agreement provided for a payment to Ms. Ecker of $210,468, less applicable withholding taxes, and 12 months of ODEC paid medical insurance premiums valued at $21,487, in the aggregate. In consideration of the promises made in the agreement, Ms. Ecker released ODEC from any claims associated with her retirement. Ms. Ecker also received $24,286 for unused vacation.

Based upon a hypothetical termination date of December 31, 2017, Mr. Kees and Mr. Beam would only be entitled to the benefits accrued under the retirement plans in which they participate, and any unused vacation. See "Plans" above and "Defined Benefit Plans" below for more information as to the benefits that would be paid under the retirement plans in which they participate.

Defined Benefit Plans

The following table lists the estimated values under the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan as of December 31, 2017. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits was limited to $270,000 effective January 1, 2017.

PENSION BENEFITS

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Year
Jackson E. Reasor [(1)]	NRECA Retirement Security Plan	2.83	$ 206,992	$ —
	Deferred Compensation Pension Restoration Plan	—	—	88,949
	Severance Pay Pension Restoration Plan [(1)]	—	106,699	—
Robert L. Kees	NRECA Retirement Security Plan	2.92	213,081	—
	Deferred Compensation Pension Restoration Plan	—	—	7,847
D. Richard Beam	NRECA Retirement Security Plan	30.33	2,176,790	—
	Deferred Compensation Pension Restoration Plan	30.33	134,015	—
Elissa M. Ecker [(2)]	NRECA Retirement Security Plan	11.42	584,452	—

(1) Beginning in 1998 through December 31, 2006, Mr. Reasor participated in a Severance Pay Pension Restoration Plan and was the only participant in the plan. Mr. Reasor's accrued benefits under this plan were frozen and paid to Mr. Reasor upon his retirement from ODEC effective January 15, 2018.

(2) Ms. Ecker retired from ODEC effective April 15, 2017.

The pension benefits indicated above are the estimated amounts payable by the plan, and they are not subject to any deduction for social security or other offset amounts. The participant's annual pension at his or her normal retirement date, currently age 62, is equal to the product of his or her years of benefit service times final average salary times the multiplier in effect during years of benefit service. The multiplier was 1.7% commencing January 1, 1992. The number of years of credited service is as of the end of the current year for each of the named executives. The present value of accumulated benefit is calculated assuming that the executive retires at the normal retirement age per the plan, but using current number of years of credited service, and that he or she receives a lump sum. The lump sum amounts are calculated using the 30-year Treasury rate (2.86% for 2017, and 3.03% for 2016) and the PPA three segment yield rates (1.79%, 3.80%, and 4.71% for 2017, and 1.76%, 4.15%, and 5.13% for 2016) and the required Internal Revenue Service mortality table for lump sum payments (Group Annuity Reserving 1994, projected to 2002, blended 50%/50% for unisex mortality in combination with the 30-year Treasury rates and PPA Retirement Plan 2000 at 2017 combined unisex

50%/50% mortality in combination with the PPA rates). Lump sums at normal retirement age are then discounted to the last day of the appropriate year using these same assumptions shown for the respective stated interest rates.

During 2014, Mr. Reasor and Mr. Kees reached normal retirement age, 62, under the Deferred Compensation Pension Restoration Plan, which is intended to provide a supplemental benefit for employees who would have had a reduction in their pension benefit because of IRC limitations. In 2014, in accordance with the Deferred Compensation Pension Restoration Plan, Mr. Reasor and Mr. Kees each received payment of their respective pension restoration plan benefits as of December 31, 2014. Upon his retirement on January 15, 2018, Mr. Reasor ceased earning benefit credit and received a payment of his pension restoration plan benefit. As long as Mr. Kees continues to work for us, he will continue to earn benefit credit and may elect to receive a payment of his pension restoration plan benefits. To the extent the pension benefits exceed the IRC limits, the Deferred Compensation Pension Restoration plan provides a supplemental pension benefit.

Prior to the Deferred Compensation Pension Restoration Plan, from 1998 through 2006, Mr. Reasor participated in a Severance Pay Pension Restoration Plan, which was also intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit because of IRC limitations. Mr. Reasor was the only participant in the plan. Mr. Reasor's accrued benefits under this plan were frozen at December 31, 2004 and July 1, 2006, in the amounts of $45,852 and $60,817, respectively, for a total of $106,699. These amounts were paid to Mr. Reasor in 2018 upon his retirement.

Also during 2014, Mr. Reasor and Mr. Kees reached normal retirement age, 62, under the NRECA Retirement Security Plan, and the plan provides for quasi-retirement. Quasi-retirement refers to a one-time election option under the plan that permits a participant to receive the benefit at any time after reaching normal retirement age, even if the participant continues to work for an employer that participates in the plan. Mr. Reasor elected quasi-retirement effective February 28, 2015, Mr. Kees elected quasi-retirement effective January 31, 2015, and they each received lump sum cash distributions in 2015. Both Mr. Reasor and Mr. Kees continued to work for us and earn benefit credit. Mr. Reasor retired January 15, 2018. Mr. Kees will continue to earn benefit credit for as long as he continues to work for us. Once Mr. Kees retires, he will receive a benefit for the time worked after the quasi-retirement date. Upon separation from employment at ODEC, former employees do not receive ODEC contributions to the NRECA Retirement Security Plan. Ms. Ecker has not made contributions or received contributions from this plan since her separation from employment.

Deferred Compensation Plan

In 2006, in connection with the execution of the employment agreement with Mr. Reasor, we adopted the Deferred Compensation Plan, which is a non-qualified plan, for the purpose of providing supplemental deferred compensation to Mr. Reasor in an amount within the statutory maximums permitted under IRC Section 457. The Deferred Compensation Plan is restricted to those executive employees designated by our board of directors who are generally responsible for ongoing operations, responsible for and have general supervision over the overall financial condition, responsible for setting and executing overall corporate policies and practices, and responsible for supervising large numbers of employees and who elect to participate in the Deferred Compensation Plan by agreeing to a deferral of a portion of their current compensation. Currently, Mr. Reasor is the only participant in the Deferred Compensation Plan. Under the Deferred Compensation Plan, annual deferrals cannot exceed the lesser of 100% of Mr. Reasor's annual compensation or $18,000 for 2016 and 2017, adjusted by and subject to specified tax laws (the "deferral limit"), during any year in which we are exempt from federal income taxation. During the last three years before Mr. Reasor attained the normal retirement age under our defined benefit pension plan, the deferral limit was increased to the lesser of two times the deferral limit or the deferral limit plus the amount Mr. Reasor was eligible to but did not defer under the Deferred Compensation Plan. Mr. Reasor attained normal retirement age during 2014. Amounts credited to him under the Deferred Compensation Plan will be credited with earnings or losses equal to those made by an investment in one or more funds of a specified regulated investment company designated by him. Distributions under the Deferred Compensation Plan generally commence upon separation from employment, whether upon termination, retirement, or death.

The following table sets forth the non-qualified deferred compensation paid to our executive officers in 2017:

NON-QUALIFIED DEFERRED COMPENSATION

Name	Executive Contributions in Last Fiscal Year	Registrant Contributions in Last Fiscal Year (1)	Aggregate Gains in Last Fiscal Year	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End (2)
Jackson E. Reasor	$ —	$ 15,000	$ 46,394	$ —	$ 307,794
Robert L. Kees	n/a	n/a	n/a	n/a	n/a
D. Richard Beam	n/a	n/a	n/a	n/a	n/a
Elissa M. Ecker	n/a	n/a	n/a	n/a	n/a

(1) For Mr. Reasor, includes a $15,000 ODEC contribution to the non-qualified deferred compensation plan, which appears in the Summary Compensation table in the "All Other Compensation" column.

(2) For Mr. Reasor, $15,000 has been reported in the Summary Compensation Table as compensation for fiscal years 2016 and 2015.

Board of Directors Compensation

It is our policy to compensate the members of our board of directors who are not employed by one of our member distribution cooperatives ("outside directors"). During 2017, our outside directors were compensated by a monthly retainer of $3,000 and were also paid for meetings and other official activities at a rate of $500 per day and $250 per partial day and for teleconferences, if such meetings or other official activities occurred outside the normal board of directors meeting dates. Effective January 1, 2018, our outside directors are compensated by a monthly retainer of $3,800 and also will be paid for meetings and other official activities at a rate of $500 per day and $250 per partial day and for teleconferences, if such meetings or other official activities occurred outside the normal board of directors meeting dates. All directors are entitled to be reimbursed for out-of-pocket expenses incurred in attending meetings and other official activities. Our directors receive no other compensation from us. We do not provide our directors pension benefits, non-equity incentive plan compensation, or other perquisites and because we are a cooperative, we do not have stock or other equity options. The following table sets forth the compensation we paid to our directors in 2017:

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash	Total
Paul H. Brown	$ 40,500	$ 40,500
John J. Burke, Jr.	42,000	42,000
Darlene H. Carpenter	38,000	38,000
Earl C. Currin, Jr.	40,750	40,750
E. Garrison Drummond	37,750	37,750
Chad N. Fowler	37,500	37,500
Fred C. Garber	38,000	38,000
Hunter R. Greenlaw, Jr.	41,500	41,500
Bruce A. Henry	37,500	37,500
David J. Jones	37,750	37,750
Keith L. Swisher	37,500	37,500
	$ 428,750	$ 428,750

Compensation Committee Interlocks and Insider Participation

As described above, the executive committee of our board of directors establishes and the full board of directors approves all compensation and awards paid to our President and CEO. Our board of directors has delegated to our President and CEO the authority to establish and adjust compensation for all employees other than himself. Other than the two exceptions noted below, no member of our board of directors is or previously was an officer or employee of ODEC or is or has engaged in transactions with ODEC. Mr. Gregory W. White was an employee of ODEC from 1990 to

1996 and from 1999 to 2005 when he left his position as Senior Vice President of Power Supply to become the President and Chief Executive Officer of Northern Neck Electric Cooperative, one of our member distribution cooperatives. Mr. John C. Lee, Jr. was an employee of ODEC from 1992 to 2007 when he left his position as Vice President of Member and External Relations to become the President and Chief Executive Officer of Mecklenburg Electric Cooperative, one of our member distribution cooperatives. All of our directors are employees or directors of our member distribution cooperatives.

Under our executive committee charter, the executive committee's duties and responsibilities include (1) recommending all compensation for ODEC's President and CEO to the board of directors for its approval and (2) serving as the compensation committee of the board of directors to review and discuss with management the contents of the Compensation Discussion and Analysis section of the Annual Report on Form 10-K and to recommend to the board of directors inclusion of the Compensation Discussion and Analysis section in the Annual Report on Form 10-K each year.

Compensation Committee Report

The executive committee serves as the compensation committee of the board of directors and has reviewed and discussed with the management of ODEC the contents of the Compensation Discussion and Analysis section and, based on such review and discussion, has recommended to the board of directors its inclusion in this Annual Report on Form 10-K.

J. William Andrew, Jr., Chair
Paul H. Brown
Earl C. Currin, Jr.
Kent D. Farmer
Fred C. Garber.
John C. Lee, Jr.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Because we are a cooperative, all of our directors are representatives of our members. Our members include our member distribution cooperatives, which are our principal customers, and TEC. Due to the extent of the payments by each member distribution cooperative to us, our directors are not independent based on the definition of "independence" of the New York Stock Exchange.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table presents fees for services provided by Ernst & Young LLP for the two most recent fiscal years. All Audit, Audit-Related, and Tax Fees shown below were pre-approved by the Audit Committee in accordance with its established procedures.

	2017	2016
Audit Fees [1]	$ 337,299	$ 329,623
Audit-Related Fees [2]	15,335	—
Tax Fees [3]	8,150	7,108
Total	$ 360,784	$ 336,731

(1) Fees for professional services provided for the audit of our annual financial statements as well as reviews of our quarterly financial statements, accounting consultations on matters addressed during the audit or interim reviews, and SEC filings and offering memorandums including comfort letters, consents, and comment letters.

(2) Fees for professional services which principally include accounting consultations and due diligence services.

(3) Fees for professional services for tax-related advice and compliance.

For fiscal years 2017 and 2016, other than those fees listed above, we did not pay Ernst & Young LLP any fees for any other products or services.

Audit Committee Preapproval Process for the Engagement of Auditors

All audit, tax, and other services to be performed by Ernst & Young LLP for us must be pre-approved by the Audit Committee. The Audit Committee reviews the description of the services and an estimate of the anticipated costs of performing those services. Pre-approval is granted usually at regularly scheduled meetings. During 2017 and 2016, all services performed by Ernst & Young LLP were pre-approved by the Audit Committee in accordance with this policy.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of this Form 10-K.

1. Financial Statements

   See Index on page 47

2. Financial Statement Schedules

   Not applicable

3. Exhibits

Exhibits

*3.1 Amended and Restated Articles of Incorporation of Old Dominion Electric Cooperative (filed as exhibit 3.1 to the Registrant's Form 10-Q, File No. 000-50039, filed on November 10, 2015).

*3.2 Bylaws of Old Dominion Electric Cooperative, Amended and Restated as of July 26, 2016, as amended on July 26, 2016 (filed as exhibit 3.1 to the Registrant's Form 10-Q, File No. 000-50039, filed on August 9, 2016).

*4.1 Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee (filed as exhibit 4.1 to the Registrant's Form 10-K for the year ended December 31, 2010, File No. 000-50039, on March 16, 2011).

*4.2 First Supplemental Indenture, dated as of April 1, 2011, to the Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee, including the form of the 2011 Series A, B, and C Bonds (filed as exhibit 4.1 to the Registrant's Form 8-K dated April 7, 2011, File No. 000-50039, on April 8, 2011).

*4.3 Second Supplemental Indenture, dated as of June 1, 2013, to the Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee, including the form of the 2013 Series A and B Bond (filed as exhibit 4.1 to the Registrant's Form 8-K dated June 28, 2013, File No. 000-50039, on July 2, 2013).

*4.4 Third Supplemental Indenture, dated as of November 1, 2014, to the Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee, including the form of the 2015 Series A and B Bond (filed as exhibit 4.1 to the Registrant's Form 8-K dated January 15, 2014, File No. 000-50039, on January 16, 2015).

*, ***10.1 Second Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and A&N Electric Cooperative, dated January 1, 2009 (filed as exhibit 10.2 and 10.3 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2008, File No. 33-46795, filed on November 12, 2008).

*10.2 Nuclear Fuel Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.3 Purchase, Construction and Ownership Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.4 Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, dated as of May 31, 1990 (filed as exhibit 10.4 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.5 Amendment No. 1 to the Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, effective March 12, 1993 (filed as exhibit 10.34 to the Registrant's Form S-1 Registration Statement, File No. 33-61326, filed on April 19, 1993).

*10.6 Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of May 31, 1990 (filed as exhibit 10.6 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.7 Amendment to the Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, effective January 17, 1995 (filed as exhibit 10.8 to the Registrant's Form 10-K for the year ended December 31, 1994, File No. 33-46795, on March 15, 1995).

*10.8 Mutual Operating Agreement, dated as of May 18, 2005, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (filed as exhibit 10.66 to the Registrant's Form 10-K for the year ended December 31, 2005, File No. 000-50039, on March 21, 2006).

*10.9 Interconnection Agreement between Delmarva Power & Light Company and Old Dominion Electric Cooperative, dated November 30, 1999 (filed as exhibit 10.33 to the Registrant's Form 10-K for the year ended December 31, 2000, File No. 33-46795, on March 19, 2001).

*10.10 First Amended and Restated Credit Agreement, dated as of March 3, 2017, among Old Dominion Electric Cooperative, the lenders party thereto, the Issuing Lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender (filed as exhibit 10.1 to the Registrant's Form 8-K dated March 3, 2017, File No. 000-50039, on March 8, 2017).

*10.11 Nuclear Decommissioning Trust Agreement between Old Dominion Electric Cooperative and SunTrust Bank, (formerly Crestar Bank), dated June 1, 1999 (filed as exhibit 10.8 to the Registrant's Form 10-K for the year ended December 31, 2014, File No. 000-50039, on March 11, 2015).

*,**10.12 Equipment Operating Lease Agreement, dated as of February 29, 1996, between State Street Bank and Trust Company, as Lessor, and Old Dominion Electric Cooperative, as Lessee (filed as exhibit 10.37 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.13 Amendment No. 1 to Equipment Operating Lease Agreement, dated as of December 19, 2002, between State Street Bank and Trust Company, as Lessor, and Old Dominion Electric Cooperative, as Lessee (filed as Exhibit 10.65 to the Registrant's Form 10-K for the year ended December 31, 2002, File No. 000-50039, on March 28, 2003).

*,**10.14 Amendment No. 2 to Equipment Operating Lease Agreement (filed as exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.15 Employment Agreement, dated June 1, 2016, between Old Dominion Electric Cooperative and Jackson E. Reasor and accepted by Jackson E. Reasor on June 1, 2016 (filed as Exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on June 8, 2016).

*10.16 Employment letter, dated November 28, 2005, of Old Dominion Electric Cooperative and agreed and accepted by Robert L. Kees (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on November 28, 2005).

*10.17 Employment letter, dated March 30, 2007, of Old Dominion Electric Cooperative and agreed and accepted by Bryan S. Rogers (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on April 2, 2007).

*10.18 Executive Deferred Compensation Plan, dated June 30, 2006, adopted on December 18, 2006 (filed as exhibit 10.2 to the Registrant's Form 8-K File No. 000-50039, on December 21, 2006).

*10.19 Form of Salary Continuation Plan (filed as exhibit 10.31 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.20 Amended and Restated Severance Pay Pension Restoration Plan effective January 1, 2015 (filed as exhibit 10.41 to the Registrant's Form 10-K for the year ended December 31, 2014, File No. 000-50039, on March 11, 2015).

*10.21 Amended and Restated Deferred Compensation Pension Restoration Plan effective January 1, 2015 (filed as exhibit 10.42 to the Registrant's Form 10-K for the year ended December 31, 2014, File No. 000-50039, on March 11, 2015).

*10.22 Lease Agreement between Old Dominion Electric Cooperative and Regional Headquarters, Inc., dated July 29, 1986 (filed as exhibit 10.27 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

21 Subsidiaries of Old Dominion Electric Cooperative (not included because Old Dominion Electric Cooperative's subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" under Rule 102(w) of Regulation S-X).

31 Certification of the Principal Executive Officer and Principal Financial Officer pursuant to Rule 13a-14(a)

32 Certification of the Principal Executive Officer and Principal 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

* Incorporated herein by reference.

** The lease relates to our interest in all of Clover Unit 1 and related common facilities, other than the foundations. At the time this lease was executed, we had entered into identical leases with respect to the foundations as part of the same transactions. We agree to furnish to the Commission, upon request, a copy of the lease of our interest in the foundations for Clover Unit 1.

*** This agreement is substantially similar in all material respects to the wholesale power contracts of our other member distribution cooperatives.

ITEM 16. FORM 10-K SUMMARY

None

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

By: /s/ ROBERT L. KEES
Robert L. Kees
Interim President and Chief Executive Officer and Senior Vice President and Chief Financial Officer

Date: March 14, 2018

Signature	Title
/s/ ROBERT L. KEES Robert L. Kees	Interim President and Chief Executive Officer (Principal executive officer) Senior Vice President and Chief Financial Officer (Principal financial officer)
/s/ BRYAN S. ROGERS Bryan S. Rogers	Vice President and Controller (Principal accounting officer)
/s/ J. WILLIAM ANDREW, JR. J. William Andrew, Jr.	Director
/s/ PAUL H. BROWN Paul H. Brown	Director
/s/ JOHN J. BURKE, JR. John J. Burke, Jr.	Director
/s/ DARLENE H. CARPENTER Darlene H. Carpenter	Director
/s/ EARL C. CURRIN, JR. Earl C. Currin, Jr.	Director
/s/ E. GARRISON DRUMMOND E. Garrison Drummond	Director
/s/ JEFFREY S. EDWARDS Jeffrey S. Edwards	Director
/s/ KENT D. FARMER Kent D. Farmer	Director
/s/ CHAD N. FOWLER Chad N. Fowler	Director
/s/ FRED C. GARBER Fred C. Garber	Director
	Director

Signature	Title
/s/ HUNTER R. GREENLAW, JR. Hunter R. Greenlaw, Jr.	
/s/ STEVEN A. HARMON Steven A. Harmon	Director
/s/ MICHAEL W. HASTINGS Michael W. Hastings	Director
/s/ BRUCE A. HENRY Bruce A. Henry	Director
/s/ DAVID J. JONES David J. Jones	Director
/s/ MICHAEL J. KEYSER Michael J. Keyser	Director
/s/ JOHN C. LEE, JR. John C. Lee, Jr.	Director
/s/ MICHEAL E. MALANDRO Micheal E. Malandro	Director
/s/ KEITH L. SWISHER Keith L. Swisher	Director
/s/ MICHAEL I. WHEATLEY Michael I. Wheatley	Director
/s/ GREGORY W. WHITE Gregory W. White	Director
/s/ BELVIN WILLIAMSON Belvin Williamson	Director

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT.

ODEC does not solicit proxies from its cooperative members and thus is not required to provide an annual report to its security holders and will not prepare such a report after filing this Form 10-K for fiscal year 2017. Accordingly, ODEC will not file an annual report with the Securities and Exchange Commission.

Exhibit 31

CERTIFICATIONS

I, Robert L. Kees, certify that:

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

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;

4. I am 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 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 annual 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. I have disclosed, based on my 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: March 14, 2018

/s/ ROBERT L. KEES

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

Exhibit 32

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 Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert L. Kees, Interim President and Chief Executive Officer and 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: March 14, 2018

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