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, 2015

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

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

2015 ANNUAL REPORT ON FORM 10-K

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
CAIR	Clean Air Interstate Rule
CCRs	Coal combustion residuals
CEC	Choptank Electric Cooperative, Inc.
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Clover	Clover Power Station
CPCN	Certificate of Public Convenience and Necessity
CO_2	Carbon dioxide
CPP	Clean Power Plan
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
EP	Essential Power, LLC, formerly known as North American Energy Alliance, LLC
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPC	Engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
GHG	Greenhouse gases
Hg	Mercury
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
Norfolk Southern	Norfolk Southern Railway Company
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	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Pension Protection Act
Rabobank	Cooperative Centrale Raiffeisen Boerenleenbank B.A., “Rabobank Nederland”
RCRA	Resource Conservation and Recovery Act, as amended
REC	Rappahannock Electric Cooperative
RICE	Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants
RFP	Request for proposal
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
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
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 more than 565,000 retail electric customers (meters), representing a total population of approximately 1.4 million people in 2015.

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 forward, short-term 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. 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. These areas predominantly reflect stable growth in residential capacity and energy requirements, both in terms of power sales and number of customers. 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 three-quarters of the United States' land mass.

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

We are not a party to any collective bargaining agreement. We had 137 employees as of March 2, 2016.

Our principal executive office is located in the Innsbrook Corporate Center, at 4201 Dominion Boulevard, Glen Allen, Virginia 23060-6721. 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 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 properties, 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 2015 are as follows:

Member Distribution Cooperatives	Revenues	
	(in millions)	
Rappahannock Electric Cooperative	$ 334.2	34.5%
Shenandoah Valley Electric Cooperative	181.0	18.7
Delaware Electric Cooperative, Inc.	114.0	11.8
Choptank Electric Cooperative, Inc.	83.8	8.7
Southside Electric Cooperative	76.5	7.9
A&N Electric Cooperative	55.5	5.7
Mecklenburg Electric Cooperative	47.4	4.9
Prince George Electric Cooperative	25.4	2.6
Northern Neck Electric Cooperative	23.4	2.4
Community Electric Cooperative	16.6	1.7
BARC Electric Cooperative	11.1	1.1
Total	$ 968.9	100.0%

No individual customer of our member distribution cooperatives constituted more than 3.3% 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 are diverse and encompass primarily rural, suburban, and recreational areas. The unemployment rate in their service territories is mostly below that of the national average. 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, paper, and travel.

Our member distribution cooperatives' sales of energy in 2015 totaled approximately 12,400,000 MWh. These sales were divided by customer class as follows:

Customer Class	Percentage of MWh Sales	Percentage of Customers
Residential	59.2%	89.1%
Commercial and industrial	39.4	9.9
Other	1.4	1.0

From 2010 through 2015, our eleven member distribution cooperatives experienced a compound annual growth rate of approximately 2.7% in the number of customers and in energy sales measured in MWh. Our member distribution cooperatives' service territories continue to experience modest growth due to the expansion of suburban communities into neighboring rural areas and the continuing development of resort and vacation communities within their service territories. These annual growth rates have been impacted by acquisitions of service territories by our member distribution cooperatives.

Our eleven member distribution cooperatives' average number of customers per mile of energized line has increased approximately 4.6% since 2010 to approximately 9.4 customers per mile in 2015. System densities of our member distribution cooperatives in 2015 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 2015, 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 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 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, to the extent that we have the power and facilities available to do so.

An exception to the all-requirements obligations of the member distribution cooperatives relates to the ability of our eight mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from SEPA. Purchases under this exception constituted approximately 1.4% of our member distribution cooperatives' total energy requirements in 2015.

Two additional exceptions to the all-requirements nature of the contract permit the member distribution cooperatives to receive up to the greater of 5% of their power requirements or 5 MW from owned generation or other suppliers, and to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. In 2015, our member distribution cooperatives collectively received approximately 9 MW under these exceptions. Beginning in the second quarter of 2016, we currently anticipate that our member distribution cooperatives will collectively receive approximately 60 MW under this exception. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows.

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 at least every three years. 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 the RUS loan or guarantee programs. These member distribution cooperatives have entered into loan documents with RUS which 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 a specified times interest earned ratio and a debt service coverage ratio. Finally, we understand that the principal loan documentation of our member distribution cooperatives which 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 wholesale power costs – 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, beginning in 2013, DEC became subject to RPS. DEC meets the RPS through owned and purchased resources and purchases of renewable energy credits. DEC may receive up to the greater of 5% of their power requirements or 5 MW from owned generation or other suppliers in accordance with 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 and Maryland, including retail customers of our member distribution cooperatives located in those states, are currently permitted to purchase power from the registered supplier of their choice. In Virginia, certain large retail customers have very limited rights to choose their energy suppliers. As of March 2, 2016, no entity had registered to be an alternative power supplier in any of the service territories of our member distribution cooperatives and, as a result, none of their retail customers have 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. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Additionally, all 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 March 2, 2016, eight of our nine Virginia member distribution cooperatives provided this option. Currently, we do not anticipate that these limited rights to retail choice of our member distribution cooperatives' customers 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 $200.0 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 combustion turbine facilities – Louisa, Marsh Run, and Rock Springs; distributed generation facilities; and physically-delivered forward power purchase contracts and spot market energy purchases. Our energy supply resources for the past three years were as follows:

	Year Ended December 31,					
	2015		2014		2013	
			(in MWh and percentages)			
Generated:						
Clover	2,734,519	19.6%	2,832,463	21.2%	2,956,164	22.6%
North Anna	1,887,395	13.5	1,843,081	13.8	1,740,612	13.3
Louisa	403,489	2.9	195,230	1.4	124,360	0.9
Marsh Run	689,713	4.9	398,583	3.0	213,666	1.6
Rock Springs	297,610	2.1	104,043	0.8	130,422	1.0
Distributed Generation	1,388	—	2,184	—	444	—
Total Generated	6,014,114	43.0	5,375,584	40.2	5,165,668	39.4
Purchased:						
Other than renewable:						
Long-term and short term	6,554,835	46.8	6,021,116	45.0	5,596,624	42.7
Spot market	677,836	4.8	1,192,439	8.9	1,591,103	12.1
Total Other than renewable	7,232,671	51.6	7,213,555	53.9	7,187,727	54.8
Renewable (1)	751,458	5.4	786,411	5.9	752,990	5.8
Total Purchased	7,984,129	57.0	7,999,966	59.8	7,940,717	60.6
Total Available Energy	13,998,243	100.0%	13,375,550	100.0%	13,106,385	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.

Clover and North Anna, our baseload generating facilities, satisfied approximately 23.6% of our capacity obligations and 33.1% of our energy requirements in 2015. Louisa, Marsh Run and Rock Springs, our peaking generating facilities, collectively provided 44.7% of our capacity obligations, and 9.9% of our energy requirements in 2015. For a description of our generating facilities, see "Properties" in Item 2. In 2015, we obtained the remainder of our capacity obligations 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 various suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. See "Power Purchase Contracts" below.

In 2015, our member distribution cooperatives' peak demand occurred in February and was 3,315 MW, excluding power supplied by SEPA, which is not an ODEC resource. See "Members—Member Distribution Cooperatives—Wholesale Power Contracts."

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 our combustion turbine facilities, 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. Our goal is to supply 50% to 70% of our energy needs from our owned generation and long-term contracted resources. 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 or development of additional generating facilities.

Wildcat Point

We are constructing, and will be the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We had a ground lease related to land and land rights associated with Wildcat Point that was being accounted for as an operating lease. During 2015, we purchased the land and these land rights from EP for $40.0 million. As a result of the purchase of the land and land rights, we currently anticipate that the project cost will be approximately $834.3 million, including capitalized interest. To fund a portion of the project cost, on January 15, 2015, we issued $332.0 million of first mortgage bonds in a private placement transaction.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. Beginning in June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through December 31, 2015, we capitalized construction costs related to Wildcat Point totaling $488.7 million, including $12.6 million of capitalized interest. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Wildcat Point" in Item 7.

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 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 dramatically in recent years. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Operating Expenses” in Item 7. We anticipate that our transmission costs will continue to increase in 2016.

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, 2019. 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. In December 2014, PJM proposed multiple changes to RPM and on June 9, 2015, FERC approved most of PJM’s proposed changes, including a new component called "capacity performance". These changes are expected to result in higher capacity clearing prices and are intended to increase the availability of generating units, especially during emergency conditions. This could enable generation owners, such as ODEC, to earn increased compensation for capacity for certain generating units. While generating units have the potential to earn increased compensation for capacity, they are exposed to significantly higher charges if they 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, capacity revenue will only be paid to generating units offered as a capacity performance unit. 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 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 have also contracted with a company for the output of two solar facilities that are projected to be in service by the end of 2016. We do not own or operate any of these facilities and are not responsible for their operational costs.

Fuel Supply

Coal

Virginia Power, as operating agent of Clover, has the responsibility to procure sufficient coal for the operation of 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, 2015, and December 31, 2014, there was a 69-day and a 70-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.

Natural Gas

Our three combustion turbine facilities 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 Louisa, Marsh Run, and Rock Springs. We have developed and utilize a natural gas supply strategy for providing natural gas to each of the three combustion turbine facilities. 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, as well as our proposed Wildcat Point facility, 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 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.

Our rates and services are regulated by FERC. The VSCC, the DPSC, and the MPSC do not have jurisdiction over our rates, charges, and services.

Regulatory Proceedings Related to Wildcat Point

The development, construction, and operation of Wildcat Point are subject to governmental and regulatory approvals. See "Power Supply Resources—Wildcat Point" above.

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 $10.0 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 $10.0 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 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. 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 $1.3 million and $2.7 million in 2015 and 2014, respectively. Additionally, in 2014, we procured and capitalized $3.4 million of emission reduction credits related to the construction of Wildcat Point.

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, PM, Hg, 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.

We are impacted by the following regulations under the CAA:

- Cross-State Air Pollution Rule
- Acid Rain Program
- Mercury and Air Toxics Standards
- Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants
- 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. CSAPR was originally scheduled to go into effect in 2012, however numerous petitions by industry participants resulted in a successful motion for stay of the implementation of the law. In October 2014, the D.C. Circuit granted the EPA's motion to lift the stay of CSAPR. Further, the D.C. Circuit granted the EPA's request to shift the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets (which would have gone into effect in 2012 and 2013) apply in 2015 and 2016, and Phase 2 emissions budgets apply in 2017 and beyond. Based upon published allocations/new source set asides 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 and the majority of emissions allowances projected to be required when Wildcat Point commences operation. Because the CSAPR allowance market is relatively new, we cannot predict the potential financial impacts of such purchases.

Wildcat Point can apply for set-aside new source 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.

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 is included in the Acid Rain Program budget and receives an annual allocation of SO_2 allowances at no cost based upon its baseline operations. Newer facilities, including Louisa, Marsh Run, Rock Springs, and Wildcat Point, need to obtain allowances under the Acid Rain Program; however, because they are primarily gas-fired generating facilities, the number of SO_2 allowances they 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 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.

Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants ("RICE")

Under the RICE standards, compression ignition diesel engines used for emergency/black start power or for firewater pumping at the power stations will only have to maintain records of the hours of operation and document regular preventive maintenance. Our five distributed generation facilities that are operated at various remote substations have the capability to operate for peak shaving purposes in addition to supplying power during emergency situations. Based upon continuing this capability, we installed the required control equipment and monitoring systems prior to the 2013 compliance date. We have an additional distributed generation facility that is scheduled to become operational in the first half of 2016, which will be in compliance with the New Source Performance Standards and RICE maximum achievable control technology.

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. On October 1, 2015, the EPA changed the NAAQS for ground-level ozone to 70 parts per billion (ppb) from 75 parts per billion. We anticipate that the EPA will finalize designations of the revised ozone NAAQS in late 2017. 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 as a result of this change in the NAAQS. 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 existing or planned facilities.

CO_2 New Source Performance Standards for EGUs

On October 23, 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")

On October 23, 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 establishes 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 EPA also published proposed Federal Plan and Model Rules, which are expected to be finalized in early summer 2016. Under the final Clean Power Plan, states must submit a single State Implementation Plan (SIP) by September 2016, or a multi-state plan by September 2017. The SIP will need to address, among other things, the inclusion of new units in the goals, the treatment of nuclear units, and the selection of a rate-based or mass-based program. In addition, the SIP must propose methods of achieving emissions reduction goals, which may include increasing efficiency of existing fossil-fuel plants, increasing energy conservation, and increasing renewable and other non-emitting energy technologies. The items the SIP will need to address will be very important in understanding how the Clean Power Plan will affect us.

The primary court 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. We are monitoring the litigation, and are utilizing stakeholder processes to engage the state agencies charged with developing the state plans. We currently cannot predict the impact of the Clean Power Plan on our existing facilities due to the complexities of this rulemaking and the ongoing litigation.

Greenhouse Gas Permitting of Operating Units

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 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 operating permits.

Regional Greenhouse Gas Initiative ("RGGI")

RGGI provides for a cap-and-trade program to regulate CO_2 emissions among certain northeastern and mid-Atlantic states, including Delaware and Maryland. Since Rock Springs is located in Maryland, we are required to purchase RGGI CO_2 emissions allowances for each ton of CO_2 emitted by our Rock Springs units. Additionally, Wildcat Point will be required to purchase RGGI CO_2 emissions allowances for each ton of CO_2 emitted once operational. The regulations require all allowances to be auctioned rather than allocated directly to utilities. There is currently an adequate quantity of CO_2 allowances available for purchase to support Rock Springs and Wildcat Point.

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 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. 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 Recovery Act ("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 - 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 the Federal Register on April 17, 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 in the process of making modifications to Clover to comply with RCRA.

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.

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 2015, we purchased approximately 57.0% 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 and likely will increase until the anticipated commercial operation of Wildcat Point in mid-2017, as our member distribution cooperatives' requirements for power increase. Our reliance on energy purchases could also increase because the operation of our generating facilities is subject to many risks, including the shutdown of our facilities, 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.

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, as well as changes in 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;
- the transportation of fuels;
- price competition among fuels used to produce electricity, including natural gas, coal, and oil;
- energy transmission or natural gas transportation capacity constraints;
- the impact of implementation of new technologies in the power industry;
- 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.

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. 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 monitoring the legal challenges to the Clean Power Plan, and are utilizing stakeholder processes to engage the state agencies charged with developing the state plans. 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 incomplete status of state implementation.

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 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 2015, 65.0% 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.

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 13.5% of our energy requirements in 2015. 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 or expansion 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.

We are in the process of constructing a new combined cycle generating facility, Wildcat Point, which will result in significant capital expenditures. Construction and expansion 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 or potential partners 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, 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 likely more costly replacement energy on the open market.

Failure of an investment in a lease of our interest in Clover Unit 1 could reduce investment income currently used to fund the majority of our rental payment obligations and fixed purchase price.

In conjunction with our 1996 lease and subsequent leaseback of our interest in Clover Unit 1, we purchased an investment that provides for a substantial portion of our periodic rent payments under the leaseback and the fixed purchase price of our interest in Unit 1 at the end of the term of the leaseback, if we exercise our option to purchase the interest at that time. The investment, which had a balance of $307.3 million at December 31, 2015, was issued by Rabobank, which has senior debt obligations which are currently rated "A+" by S&P and "Aa2" by Moody's. If Rabobank fails to make disbursements from the investment, we remain liable for all rental payments under the leaseback and the fixed purchase price if we choose to exercise that option. At December 31, 2015, the total balance of our remaining lease obligation was $341.5 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Uses—Significant Contingent Obligations—Clover Lease" in Item 7.

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

S&P, Moody's, and Fitch Ratings, Inc., 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 Ratings, Inc. 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. Also, we may be required to pay higher interest rates on financings which we may need to undertake in the future, and our potential pool of investors and funding sources could decrease. In addition, in limited circumstances, we have obligations to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's. These circumstances relate to the lease and leaseback of our undivided interest in Clover Unit 1 and some of our power purchase contracts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Uses—Significant Contingent Obligations" in Item 7. 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.

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

As a result of EPACT of 2005, 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 its 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.

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 retaliatory 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. We have programs and procedures in place to safeguard our operating systems. Instability in financial markets as a result of terrorism, war, sabotage, cyber security breach, natural disasters, pandemic, credit crises, recession, or other factors could result in a significant decline in 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.

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 five 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	50.0% [2]	Halifax County, Virginia	Coal	Unit 1 – 10/1995	219 MW
				Unit 2 – 03/1996	218 MW
					437 MW
North Anna	11.6%	Louisa County, Virginia	Nuclear	Unit 1 – 06/1978[3]	110 MW
				Unit 2 – 12/1980[3]	110 MW
					220 MW
Louisa	100.0%	Louisa County, Virginia	Natural Gas[4]	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	100.0%	Fauquier County, Virginia	Natural Gas[4]	Unit 1 – 09/2004	168 MW
				Unit 2 – 09/2004	168 MW
				Unit 3 – 09/2004	168 MW
					504 MW
Rock Springs	50.0% [5]	Cecil County, Maryland	Natural Gas	Unit 1 – 06/2003	168 MW
				Unit 2 – 06/2003	168 MW
					336 MW
Distributed Generation	100.0%	Multiple	Diesel	07/2002	20 MW
				Total	2,021 MW

(1) Represents an approximation of our entitlement to the maximum dependable capacity 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.
(2) Our interest in Clover Unit 1 is subject to a long-term lease. See "Clover—Clover Lease" below.
(3) We purchased our 11.6% undivided ownership interest in North Anna in December 1983.
(4) The units at this facility also operate on No. 2 distillate fuel oil.
(5) We own 100.0% of two units, each with a net capacity rating of 168 MW and 50.0% of the common facilities for the facility. See "Combustion Turbine Facilities—Rock Springs" below.

Clover

Virginia Power, the co-owner of Clover, is responsible for operating Clover 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.

Clover Lease

In 1996, we entered into a lease with an owner trust for the benefit of an investor in which we leased our interest in Clover Unit 1 and related common facilities, subject to the lien of the Indenture, for a term extendable by the owner trust up to the full productive life of Clover Unit 1, and simultaneously entered into an approximately 21.8-year leaseback of the interest. The interest of the owner trust in Clover Unit 1 is subject and subordinate to the lien of the Indenture. The lease contains events of default, which, if they occur, could result in termination of the lease and, consequently, our loss of possession and right to the output of Clover Unit 1. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Significant Contingent Obligations—Clover Lease" in Item 7 for a discussion of our options and obligations at the end of the term of the leaseback of Clover Unit 1 and sources of funding for these obligations.

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, is responsible for operating North Anna. Virginia Power also has the authority and responsibility to procure 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 arrangement for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Rock Springs

ODEC and EP each individually own two units (a total of 336 MWs each) and 50.0% of the common facilities at Rock Springs. Additionally, ODEC and EP 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 Co., LLC, an affiliate of EP, pursuant to a service agreement under which Essential Power Operating Co., 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 distributed generation facilities in our member distribution cooperatives' service territories primarily to enhance our system's reliability. We have 8 MW and 12 MW of distributed generation to serve our member distribution cooperatives in the Virginia mainland territory and the Delmarva Peninsula territory, respectively. We are currently installing an additional 6 MW of distributed generation in the Virginia mainland territory and anticipate commercial operation in the first half of 2016.

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 EP. As a transmission owner in PJM, we have relinquished dispatch control of all of these transmission facilities to PJM and contracted with third parties to operate and maintain them.

In 2013, we commenced a project to construct 14.5 miles of new 69 kV transmission line and to rebuild 14.5 miles of existing 69 kV line on the Delmarva Peninsula. The project was completed in the fourth quarter of 2015. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Uses—Capital Expenditures" in Item 7.

Wildcat Point

We are constructing, and will be the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Wildcat Point” in Item 7.

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. We received an initial decision from the hearing judge on April 13, 2015. The hearing judge found many components of the formula rate to be just and reasonable. We believe all components of the formula rate are just and reasonable and addressed the components the hearing judge found to be unjust and unreasonable in our brief on exceptions. Briefs on exceptions to the initial decision and briefs opposing exceptions to the initial decision were filed on May 13, 2015, and June 2, 2015, respectively. The FERC commissioners have the ultimate authority in this proceeding and they have no timetable to issue a final order. Our formula rate remains in effect subject to refund pending a final order from FERC. If a refund is ultimately determined, we believe it will result in a reallocation of costs among our member distribution cooperatives.

Other

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, 2015, 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,				
	2015	2014	2013	2012	2011
	(in thousands, except ratios)				
Statement of Operations Data					
Operating Revenues	$ 1,020,028	$ 951,576	$ 842,069	$ 842,681	$ 891,539
Operating Margin	48,953	50,525	52,590	59,145	62,590
Net Margin attributable to ODEC	11,879	9,100	9,573	9,939	10,807
Margins for Interest Ratio	1.27	1.21	1.21	1.21	1.22

	December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except ratios)				
Balance Sheet Data					
Net Electric Plant	$ 1,457,573	$ 1,097,669	$ 965,378	$ 991,340	$ 1,012,905
Total Investments	254,624	252,062	255,984	263,024	235,199
Other Assets	296,222	289,011	309,235	289,157	325,876
Total Assets	$ 2,008,419	$ 1,638,742	$ 1,530,597	$ 1,543,521	$ 1,573,980
Patronage capital	$ 390,976	$ 379,097	$ 369,997	$ 360,424	$ 350,485
Non-controlling interest	5,704	5,687	5,691	13,257	13,093
Long-term debt	1,024,746	721,038	749,330	737,836	766,128
Revolving credit facility	—	86,000	—	—	—
Long-term debt due within one year	28,292	28,292	28,292	28,292	28,292
Total Capitalization and Short-term Debt	$ 1,449,718	$ 1,220,114	$ 1,153,310	$ 1,139,809	$ 1,157,998
Equity Ratio (1)	27.1%	31.2%	32.2%	32.0%	30.6%

(1) 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.

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, 2015, were primarily impacted by the continuing effects from the unusually cold weather in the first quarter of 2014 on deferred energy, fuel, and transmission expense, and the construction of Wildcat Point.

- The unusually cold weather experienced in the entire mid-Atlantic region during the first quarter of 2014 continued to impact our operating results through 2015. Increased costs in the first quarter of 2014, particularly fuel expense for our combustion turbine facilities, resulted in the under-collection of our energy costs, and an under-collected deferred energy balance of $56.2 million at March 31, 2014. To address the under-collection of costs, we increased our total energy rate during 2014. At December 31, 2015, our deferred energy balance was an over-collection of $27.8 million.

- Transmission expense increased $37.7 million, or 49.6%, in 2015 as compared to 2014, primarily due to an increase in PJM charges for network transmission services, which are a function of transmission rates and billing determinants. Billing determinants are based on our usage during the peak hour of the prior PJM transmission year for each transmission area. The 2015 billing determinants for transmission were approximately 25% higher than the 2014 billing determinants due to the unseasonably cold weather in January 2014.

- We continue with the construction of Wildcat Point. Through December 31, 2015, we capitalized construction costs totaling $488.7 million. To fund a portion of the Wildcat Point project cost, on January 15, 2015, we issued $332.0 million of long-term debt, and used a portion of the proceeds to repay borrowings outstanding under our revolving credit facility.

Wildcat Point

We are constructing, and will be the sole owner of an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We had a ground lease related to land and land rights associated with Wildcat Point that was being accounted for as an operating lease. During 2015, we purchased the land and these land rights from EP for $40.0 million. As a result of the purchase of the land and land rights, we currently anticipate that the project cost will be approximately $834.3 million, including capitalized interest. To fund a portion of the project cost, on January 15, 2015, we issued $332.0 million of first mortgage bonds in a private placement transaction.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. Beginning in June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through December 31, 2015, we capitalized construction costs related to Wildcat Point totaling $488.7 million, including $12.6 million of capitalized interest.

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 and they are not necessarily indicative of the results to be expected for the year. 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 on our Consolidated Balance Sheet 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 on our Consolidated Balance Sheet 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, on our Consolidated Balance Sheet. 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 on our Consolidated Balance Sheet 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 on our Consolidated Balance Sheet and will be returned to our member distribution cooperatives in subsequent periods through our formula rate.

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. In 2015, we reduced operating revenues by $9.6 million. In 2014, we did not record an adjustment to operating revenues utilizing Margin Stabilization, since the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equaled 19.5% of our actual total interest charges. In accordance with our formula rate, no adjustment is recorded if the actual net margin attributable to

ODEC, excluding any budgeted additional equity contributions, is more than 10% but less than 20% of our actual total interest charges. In 2013, utilizing Margin Stabilization, we reduced operating revenues by $9.8 million. See "Factors Affecting Results—Formula Rate" below.

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. At December 31, 2015 and 2014, North Anna's nuclear decommissioning asset retirement obligation totaled $97.6 million, or approximately 82.6% of total asset retirement obligations, and $93.7 million, or approximately 89.3% 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 those 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, which resulted in an increase to our asset retirement obligation of $18.0 million. 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, 2015, for our asset retirement obligations related to nuclear decommissioning would have been $17.9 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 the operation of our combustion turbine facilities. 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 asset or regulatory liability, respectively, in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense in 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 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.

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. Revenues in excess of expenses in any year are designated as net margin attributable to ODEC in our Consolidated Statements of Revenues, Expenses, and Patronage Capital. We designate retained net margins attributable to ODEC in 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. Any distributions of patronage capital are subject to the discretion of our board of directors and restrictions contained in our Indenture and our syndicated credit agreement.

Formula Rate

Our power sales are comprised of two power products – energy and demand. Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as demand.

The rates we charge our member distribution cooperatives for sales of energy and demand are determined by a formula rate accepted by FERC which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

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

Energy costs, which are primarily variable costs, such as nuclear, coal, and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate rates, the base energy rate and the energy adjustment rate. Through December 31, 2013, the base energy rate was a fixed rate that required FERC approval prior to adjustment. To the extent the base energy rate over- or under-collected our energy costs, we credited or charged the difference through an energy adjustment rate. We reviewed our energy costs at least every six months to determine whether the base energy rate and the current energy adjustment rate together were recovering our actual and anticipated energy costs and revised the energy adjustment rate accordingly. Effective January 1, 2014, pursuant to FERC's acceptance of revisions to the formula rate as issued in FERC's December 2, 2013 order, the base energy rate is no longer a fixed rate that requires FERC approval prior to adjustment. The base energy rate now is developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the energy adjustment rate will be zero. With board approval, we can revise the energy adjustment rate at any time during the year if it becomes apparent that the combined base energy rate and the current energy adjustment rate are over-collecting or under-collecting our actual and anticipated energy costs. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part 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. Through December 31, 2013, we collected our total demand costs through a single demand rate. Effective January 1, 2014, pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order, we now collect our total demand costs through the following three separate rates:

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

As stated above, our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. We establish our demand rates to produce a net margin attributable to ODEC equal to 20% of our budgeted total interest charges plus additional equity contributions approved by our board of directors. Through December 31, 2013, utilizing Margin Stabilization, we adjusted our operating revenues to reflect actual demand costs incurred, including a net margin attributable to ODEC equal to 20% of actual interest charges plus additional equity contributions approved by our board of directors. Effective January 1, 2014:

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

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 under 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 on our Consolidated Statements of Revenues, Expenses, and Patronage Capital reflect the actual demand-related costs we incurred plus the energy costs that we collected during each calendar quarter and at year-end. 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.

Through December 31, 2013, we billed our total demand costs to each of our member distribution cooperatives based on its requirement for energy during the hour of the month when the need for energy among all of the customers in the Virginia mainland or the Delmarva Peninsula, as applicable, was highest, as measured in MW. The hour of the month when the need for energy is highest is referred to as the coincident peak. Through December 31, 2013, and currently, we billed energy to each of our member and non-member customers based on the total MWh delivered to them each month. Effective January 1, 2014, pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order, we now bill and collect our total demand costs through three separate rates: a transmission service rate, an RTO capacity service rate, and a remaining owned capacity service rate. See "Factors Affecting Results—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 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

Growth in the number of customers and growth in 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 three years ended December 31, were as follows:

	2015	2014	2013
Heating degree days	3,492	3,869	3,461
Cooling degree days	1,369	1,064	1,131

- *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 impacts the requirements for power.

For additional discussion of our member distribution cooperatives' customers' growth, 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 2015, we satisfied approximately 68.3% of our member distribution cooperatives' capacity requirements and 43.0% of their energy requirements through our ownership interests in Clover, North Anna, Louisa, Marsh Run, and Rock Springs, and we purchased power under physically-delivered forward contracts and in the spot market to supply the remaining needs of our member distribution cooperatives. See “Business—Power Supply Resources” in Item 1 and “Properties” in Item 2.

In 2014, we began construction of an approximate 1,000 MW natural gas-fueled 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 dramatically in recent years. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Operating Expenses” in Item 7. We anticipate that our transmission costs will continue to increase in 2016.

Generating Facilities

Our operating expenses, and consequently our rates to our member distribution cooperatives, are significantly affected by the operations of our baseload generating facilities, Clover and North Anna. Baseload generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs. Nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities have relatively low variable costs as compared to combustion turbine facilities such as Louisa, Marsh Run, and Rock Springs. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility; however, they may be more expensive to operate and, as a result, are dispatched only when the market price of energy makes their operation economical or when their operation is required by PJM to meet system reliability requirements. Recent prices of natural gas have made the operation of our combustion turbine facilities economical, resulting in increased dispatch.

As previously mentioned, our generating facilities 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. The operational availability of our owned generating resources for the past three years was as follows:

	Year Ended December 31,		
	2015	2014	2013
Clover	84.4%	87.7%	96.3%
North Anna	96.5	93.9	88.8
Louisa	97.2	96.8	97.8
Marsh Run	95.7	98.7	95.4
Rock Springs	79.9	94.9	97.1

In the fall of 2015, both units at Rock Springs experienced unscheduled maintenance outages that lasted approximately 67 and 71 days. Both units were available for operation on November 20, 2015.

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,		
	2015	2014	2013
Clover	72.1%	74.7%	78.0%
North Anna	98.2	95.9	90.6

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,		
	2015	2014	2013	2015	2014	2013
		(in days)			(in days)	
Scheduled	86.4	72.0	15.7	20.5	34.0	65.2
Unscheduled	27.8	18.0	11.4	5.3	10.3	16.3
Total	114.2	90.0	27.1	25.8	44.3	81.5

The unscheduled outages for Clover in 2015, 2014, and 2013 were related to maintenance items associated with the boiler.

Each unit at North Anna is scheduled for refueling approximately every 18 months. While only one unit is refueled at a time, this typically results in both units being off-line for refueling during the same calendar year once every three years. During 2014, Unit 2 at North Anna was off-line for refueling. During 2013, both units at North Anna were off-line for refueling.

Increasing 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 generation 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 "Factors Affecting Results—Customers' Requirements for Power" above. Our formula rate is based on our cost of service in meeting these requirements. See "Factors Affecting Results—Formula Rate" above.

Sales to TEC

In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which ODEC is the primary beneficiary. The financial statements of TEC are consolidated and the inter-company balances are eliminated in consolidation. TEC's sales to third parties are reflected as non-member revenues; however, in 2015, 2014, and 2013, TEC had no sales to third parties.

Sales to Non-members

Sales to non-members consist of sales of excess purchased and generated energy and sales of renewable energy credits. We primarily sell excess energy to PJM at the prevailing market price at the time of sale. Excess energy is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, and changes in market conditions. Renewable energy credits that are not sold to our member distribution cooperatives are sold to non-members.

Results of Operations

Operating Revenues

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the past three years were as follows:

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Revenues from sales to:			
Member distribution cooperatives			
Energy revenues [1]	$ 607,342	$ 586,327	$ 504,886
Demand revenues	361,583	321,706	305,253
Total revenues from sales to member distribution cooperatives	968,925	908,033	810,139
Non-members [2]	51,103	43,543	31,930
Total operating revenues	$ 1,020,028	$ 951,576	$ 842,069
Average cost of energy to member distribution cooperatives (per MWh)	$ 47.86	$ 46.17	$ 40.86
Average cost of demand to member distribution cooperatives (per MWh)	28.50	25.33	24.71
Average total cost to member distribution cooperatives (per MWh)	$ 76.36	$ 71.50	$ 65.57

(1) Includes sales of renewable energy credits of $2.2 million, $1.3 million, and $1.4 million in 2015, 2014, and 2013, respectively.
(2) Includes sales of renewable energy credits of $8.5 million, $5.9 million, and $6.1 million in 2015, 2014, and 2013, respectively.

Our energy sales in MWh to our member distribution cooperatives and non-members for the past three years were as follows:

	Year Ended December 31,		
	2015	2014	2013
		(in MWh)	
Energy sales to:			
Member distribution cooperatives	12,688,672	12,699,956	12,356,005
Non-members	1,193,034	579,461	626,856
Total energy sales	13,881,706	13,279,417	12,982,861

In 2015, our energy sales in MWh to our member distribution cooperatives were relatively flat as compared to 2014. In 2014, our energy sales in MWh to our member distribution cooperatives were 2.8% higher, as compared to 2013. In the first quarter of 2015 and 2014, our member distribution cooperatives' service territory experienced extremely cold weather.

In 2015, our energy sales in MWh to non-members were 105.9% higher as compared to 2014, as a result of the increase in the volume of excess purchased and generated energy. In 2014, our energy sales in MWh to non-members were 7.6% lower as compared to 2013, as a result of the decrease in the volume of excess purchased and generated energy. Sales to non-members consist of sales of excess purchased and generated energy.

In 2015, total revenues from sales to our member distribution cooperatives increased $60.9 million, or 6.7%, as compared to 2014 due to the $39.9 million, or 12.4% increase in demand revenues primarily due to increased transmission expenses. Additionally, energy revenues increased $21.0 million, or 3.6% due to the 3.5% increase in the cost of energy sold to our member distribution cooperatives. In 2014, total revenues from sales to our member distribution cooperatives increased $97.9 million, or 12.1%, as compared to 2013 primarily due to the increase in energy revenues which was driven by increases in our total energy rate and volume of energy sales in MWh.

The average cost per MWh to our member distribution cooperatives is affected by changes in our revenues as well as sales volumes. In 2015, our average total cost to member distribution cooperatives per MWh was 6.8% higher as compared to 2014 as a result of an increase in demand costs primarily related to transmission expense and the net increase in our total energy rate. In 2014, our average total cost to member distribution cooperatives per MWh was 9.0% higher as compared to 2013.

The following table summarizes the changes to our total energy rate since 2013 which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Rate Change:	% Change
April 1, 2013	(2.4)
October 1, 2013	4.7
January 1, 2014	0.5
April 1, 2014	11.8
October 1, 2014	2.4
January 1, 2015	(0.3)
July 1, 2015	(2.9)
January 1, 2016	(5.4)

Non-member revenue increased $7.6 million, or 17.4%, in 2015 as compared to the same period in 2014, due to the 13.2% increase in revenue from sales of excess energy and the 44.1% increase in revenue from sales of renewable energy credits. The increase in revenue from sales of excess energy was primarily due to a 105.9% increase in the volume of excess energy sales, partially offset by a 45.0% decrease in the average price of excess energy. We primarily sell excess energy to PJM at the prevailing market price at the time of sale. Excess energy is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, and changes in market conditions.

Non-member revenue increased $11.6 million, or 36.4%, in 2014 as compared to the same period in 2013, due to a 45.7% increase in revenue from sales of excess energy slightly offset by a 3.3% decrease in revenue from sales of renewable energy credits. The increase in revenue from sales of excess energy was primarily due to a 57.7% increase in the average price of excess energy sold which was sold at the prevailing market price.

Operating Expenses

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

	Year Ended December 31,		
	2015	2014	2013
		(in thousands)	
Fuel	$ 159,917	$ 213,528	$ 133,592
Purchased power	494,909	518,814	463,159
Transmission	113,622	75,959	66,590
Deferred energy	47,783	(57,141)	(18,834)
Operations and maintenance	49,768	49,599	41,546
Administrative and general	37,448	40,279	42,385
Depreciation and amortization	45,168	42,049	42,346
Amortization of regulatory asset/(liability), net	9,496	5,838	6,310
Accretion of asset retirement obligations	4,695	3,870	3,980
Taxes, other than income taxes	8,269	8,256	8,405
Total Operating Expenses	$ 971,075	$ 901,051	$ 789,479

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 were $70.0 million, or 7.8% higher for 2015 as compared to 2014, primarily as a result of the increases in deferred energy and transmission, partially offset by the decreases in fuel and purchased power expense.

- Deferred energy expense increased $104.9 million. In 2015, we over-collected $47.8 million, whereas in 2014, we under-collected $57.1 million. Deferred energy expense represents the difference between energy revenues and energy expenses.
- Transmission expense increased $37.7 million, or 49.6%, primarily due to an increase in PJM charges for network transmission services, which are a function of transmission rates and billing determinants. See "Power Supply Resources—PJM" in Item 1. Billing determinants are based on our usage during the peak hour of the prior PJM transmission year for each transmission area. The 2015 billing determinants for transmission were approximately 25% higher than the 2014 billing determinants due to the unseasonably cold weather in January 2014.
- Fuel expense decreased $53.6 million, or 25.1%, primarily due to the 72.6% decrease in the average cost of fuel for our combustion turbine facilities, partially offset by the 99.3% increase in the dispatch of our combustion turbine facilities.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased $23.9 million, or 4.6%, primarily due to the 4.9% decrease in the average cost of purchased energy.

Total operating expenses were $111.6 million, or 14.1% higher for 2014 as compared to 2013. The increases in fuel, purchased power, transmission, and operations and maintenance expenses were offset by the decrease in deferred energy.

- Fuel expense increased $79.9 million, or 59.8%, primarily due to the 49.0% increase in the dispatch of our combustion turbine facilities as well as the 164.6% increase in the average cost of fuel for our combustion turbine facilities.
- Purchased power expense increased $55.7 million, or 12.0%, primarily due to the 11.0% increase in the average cost of purchased energy.
- Transmission expense increased $9.4 million, or 14.1%, primarily due to an increase in PJM rates for network transmission services. See “Power Supply Resources—PJM” in Item 1.
- Operations and maintenance expense increased $8.1 million, or 19.4%, primarily due to scheduled maintenance outages at Clover.
- Deferred energy expense decreased $38.3 million. In 2014, we under-collected $57.1 million in energy costs, whereas in 2013, we under-collected $18.8 million.

Other Items

Gain/(loss) on Investments, Net

In accordance with regulatory accounting, we defer the difference between asset retirement expense, and interest income and realized gains and losses on the nuclear decommissioning trust, to our regulatory liability (North Anna asset retirement obligation deferral). See Note 10 of the Notes to Consolidated Financial Statements. In December 2013, the investments in the nuclear decommissioning trust were rebalanced resulting in a net realized gain of $2.3 million. The gain is recorded in “Gain/(loss) on investments, net” on the Consolidated Statements of Revenues, Expenses, and Patronage Capital; however, the gain is deferred to the regulatory liability referred to above via “Amortization of regulatory asset/(liability), net.” Therefore, there is no net impact on the Consolidated Statements of Revenues, Expenses, and Patronage Capital. The impact on the Consolidated Statements of Cash Flows is reflected in the purchases of and proceeds from sale of available for sale securities.

Investment Income

Investment income decreased in 2015 by $1.8 million, or 24.9%, as compared to 2014, primarily due to lower income earned on our nuclear decommissioning trust. Investment income increased in 2014 by $2.0 million, or 37.8%, as compared to 2013, primarily due to higher income earned on our nuclear decommissioning trust.

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. Following the 2015 approval by the VSCC of the recovery of 70% of North Anna Unit 3 costs in Virginia Power's rate case, we received a payment of $22.5 million, consisting of $16.1 million of our regulatory asset plus $6.4 million of interest income on these costs. 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,		
	2015	2014	2013
		(in thousands)	
Interest on long-term debt	$ (58,065)	$ (45,058)	$ (46,753)
Interest on revolving credit facility	(710)	(1,231)	(847)
Other interest	(623)	(340)	(325)
Total interest charges	$ (59,398)	$ (46,629)	$ (47,925)
Allowance for borrowed funds used during construction	13,771	936	245
Interest charges, net	$ (45,627)	$ (45,693)	$ (47,680)

In 2015, interest charges, net was relatively flat as compared to the prior year primarily as a result of the increase in interest on long-term debt due to the January 2015 debt issuance, offset by the increase in allowance for borrowed funds used during construction primarily related to Wildcat Point. In 2014, interest charges, net decreased $2.0 million, or 4.2%, primarily as a result of the decrease in total interest charges due to scheduled principal payments on long-term debt.

Net Margin Attributable to ODEC

In 2015, our 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 by $2.8 million, or 30.5%, as compared to 2014, primarily as a result of the increase in total interest charges. In 2014, our net margin attributable to ODEC, decreased $0.5 million, or 4.9%, as compared to 2013, due to lower total interest charges in 2014 as compared to 2013, and demand revenues that produced a net margin attributable to ODEC that equaled 19.5% of our actual total interest charges. See “Factors Affecting Results—Formula Rate” above.

Financial Condition

The principal changes in our financial condition from December 31, 2014 to December 31, 2015, were caused by the increases in construction work in progress, long-term debt, accounts payable–members, the decreases in revolving credit facility and regulatory assets, and the change in deferred energy.

- Construction work in progress increased $369.4 million primarily due to expenditures related to Wildcat Point.
- Long-term debt increased $303.7 million primarily due to issuance of long-term debt on January 15, 2015.
- Accounts payable–members increased $63.2 million due to the increase in member prepayments and the increase in amounts owed to our member distribution cooperatives under Margin Stabilization.
- Revolving credit facility decreased $86.0 million due to repayment of outstanding borrowings under our revolving credit facility.
- Regulatory assets decreased $26.9 million primarily due to the receipt of a $16.1 million payment from Virginia Power related to the recovery of North Anna Unit 3 costs and the amortization of the remaining balance of $6.6 million.
- Deferred energy changed $47.8 million as a result of the over-collection of our energy costs in 2015. The deferred energy balance changed from a $19.9 million asset (under-collection) at December 31, 2014, to a $27.8 million liability (over-collection) at December 31, 2015.

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 2015, 2014, and 2013, our operating activities provided cash flows of $219.3 million, $16.8 million, and $20.1 million, respectively. Operating activities in 2015 were primarily impacted by the following:

- Current liabilities changed $62.7 million primarily due to the $63.2 million increase in accounts payable–members.
- Deferred energy changed $47.8 million due to the over-collection of energy costs in 2015.
- Regulatory assets and liabilities changed $27.0 million primarily due to the recovery and amortization of the North Anna Unit 3 regulatory asset, totaling $22.7 million.

Revolving Credit Facility

We maintain a $500.0 million revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019. We did not have any borrowings outstanding under this facility at December 31, 2015; however, the interest rate on any borrowings would have been 1.4%. At December 31, 2015, we had letters of credit in the amount of $8.2 million outstanding under this facility. At December 31, 2014, we had $86.0 million in borrowings outstanding under this facility, at an interest rate of 1.5%, and a $10.0 million letter of credit.

The revolving 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 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.

Our 2002 Series A Bonds, with an aggregate principal amount of $60.2 million outstanding, were subject to optional redemption by ODEC on or after June 1, 2013. We issued a call notice for the 2002 Series A Bonds in the second quarter of 2013 and redeemed these bonds on June 1, 2013.

On June 28, 2013, we issued $100.0 million of first mortgage bonds in a private placement transaction. The issuance consisted of $50.0 million of 4.21% First Mortgage Bonds, 2013 Series A due December 1, 2043, and $50.0 million of 4.36% First Mortgage Bonds, 2013 Series B due December 1, 2053.

On January 15, 2015, we issued $332.0 million of first mortgage bonds in a private placement transaction. The issuance consisted of $260.0 million of 4.46% First Mortgage Bonds, 2015 Series A due December 1, 2044, and $72.0 million of 4.56% First Mortgage Bonds, 2015 Series B due December 1, 2053.

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 frequently 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 2013 through 2018:

	Actual Year Ended December 31,			Projected Year Ended December 31,		
	2013	2014	2015	2016	2017	2018
	(in millions)					
Wildcat Point	$ 6.0	$ 80.8	$ 331.7	$ 317.6	$ 98.2	$ 2.0
Clover	7.1	17.5	14.3	9.9	10.5	1.7
North Anna nuclear fuel	7.3	16.4	6.3	10.4	18.3	18.1
North Anna	6.4	7.5	9.2	7.7	5.3	4.3
Transmission	3.6	9.9	8.1	4.1	3.6	3.5
Combustion turbine facilities	1.0	1.0	2.3	0.4	1.2	1.1
Other	0.7	2.8	1.6	3.2	3.3	1.4
Total	$ 32.1	$ 135.9	$ 373.5	$ 353.3	$ 140.4	$ 32.1

Nearly all of our capital expenditures consist of additions to electric plant and equipment, particularly for the construction of Wildcat Point in the next few years. Capital expenditures for "Other" include costs related to our administrative and general assets, and distributed generation facilities. 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 2018.

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, 2015:

	Payments due by Period				
	Total	2016	2017-2018	2019-2020	2021 and Thereafter
	(in millions)				
Long-term debt obligations	$ 2,034.3	$ 82.5	$ 160.0	$ 153.4	$ 1,638.4
Power purchase obligations	845.2	245.0	334.7	265.5	—
Asset retirement obligations	386.0	—	4.8	0.1	381.1
Operating lease obligations	111.7	0.5	109.8	0.9	0.5
Construction obligations	254.9	218.5	36.4	—	—
Total	$ 3,632.1	$ 546.5	$ 645.7	$ 419.9	$ 2,020.0

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, 2015, 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.

On January 15, 2015, we issued $332.0 million of first mortgage bonds in a private placement transaction. See "Liquidity and Capital Resources—Sources—Financings" above.

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 our lease of our interest in Clover Unit 1. In limited circumstances, we have obligations to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's. These circumstances relate to our Clover Unit 1 lease and some of our purchases of power in the market.

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. At December 31, 2015, the collateral we had posted with counterparties pursuant to the hedging instruments we have in place was $14.9 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). At December 31, 2015, if our credit ratings had been below investment grade we estimate we would have been obligated to post between $600.0 million and $700.0 million of collateral with our counterparties. This calculation is based on energy prices on December 31, 2015, 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. At December 31, 2015, if PJM had determined that we needed to provide collateral to support our obligations, PJM could have asked us to provide up to approximately $11.0 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 $200.0 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. At December 31, 2015, 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 of $315.0 million 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 we received to enter into a payment undertaking agreement and to purchase an investment, which provides for substantially all of:

- our periodic rent payments under the leaseback; and
- the fixed purchase price of the interest in Unit 1 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 Unit 1 and the common facilities at that time. The fixed purchase price is $430.5 million.

After entering into the payment undertaking agreement, making the investment and paying transaction costs, we had $23.7 million remaining (the gain on the transaction) and we retained possession and our initial entitlement to the output of Unit 1.

The payment undertaking agreement was issued by Rabobank, which has senior debt obligations which are currently rated "A+" by S&P and "Aa2" by Moody's. Under this agreement, we made a payment to Rabobank; in return Rabobank agreed to make payments directly to the lender in the related lease transaction in satisfaction of a portion of our rent payment obligation under the leaseback and a portion of the fixed purchase price if we choose to exercise that option. We remain liable for all rental payments under the leaseback if Rabobank fails to make such payments, although the owner trust has agreed to pursue Rabobank before pursuing payment from us. For 2015, Rabobank paid $15.2 million of rent. At December 31, 2015, both the value of the portion of our lease obligations to be paid by Rabobank to the owner trust, as well as the value of our interest in the related payment undertaking agreement, totaled approximately $307.3 million.

In connection with the lease and leaseback, we also agreed to deliver a letter of credit to the investor to the lease within 90 days after our obligations under the Indenture are either rated below "A-" by S&P or "Baa2" by Moody's, or if such obligations are placed on negative credit watch by either S&P or Moody's while rated "A-" by S&P or "Baa2" by Moody's, respectively. If our ratings had been below this minimum rating at December 31, 2015, the estimated amount of the letter of credit we would have been required to provide was approximately $3.6 million. The amount of any letter of credit we are required to deliver in connection with the lease is impacted by the changes in market value of the investment we purchased and ultimately decreases to zero by December 18, 2018.

At the end of the term of the Clover Unit 1 leaseback, we have the option to purchase the owner trust's interest in the unit or arrange for an acceptable third party to enter into a power purchase agreement with the owner trust. If we decide to purchase the owner trust's interest in the unit, we must pay the owner trust a fixed purchase price of $430.5 million. Payments under the payment undertaking agreement are expected to fund approximately $289.7 million of these payments. These payments also will be funded by United States Treasury securities with a maturity value of $108.6 million. The remaining $32.2 million will be provided by us, but will in turn be paid to us as the holder of a loan to the owner trust. If we do not elect to purchase the owner trust's interest in Clover Unit 1, Virginia Power has an option to purchase that interest. If Virginia Power elects to purchase the interest but fails to pay the purchase price when due, we are obligated to make that payment, with interest, within 30 days.

If we elect not to purchase the owner trust's interest in Clover Unit 1, we can arrange for a third-party to purchase the owner trust's output of the unit at a price which will preserve the owner trust's net economic return as if we had purchased the related unit at the purchase option price. To be an eligible power purchaser, the third-party must have, among other things, a net worth of at least $500.0 million and minimum specified credit ratings or other acceptable credit enhancement. We would assist in transmitting power to the third-party by entering into a transmission and interconnection agreement with the owner trust. We also would be obligated to assist the owner trust in arranging new financing for the lease debt which remains outstanding at the expiration of the leaseback. We would not be obligated, however, to provide this financing. If alternate financing is not available or we otherwise fail to satisfy the conditions to arrange for a new third-party purchaser, we must either exercise our purchase option or make a termination payment to the owner trust. We also must provide management services to the owner trust if power is being sold to the third-party.

As a third option, at the end of the term of the leaseback, we may pay to the owner trust an amount equal to the difference between a specified termination amount and the fair market value of its interest in Unit 1 and return possession of the interest in the unit back to the owner trust. The amount we are obligated to pay cannot exceed the specified termination amount minus 20% of the fair market value of the owner trust's interest in the unit at the time the lease was entered into in 1996 or be less than the amount of the owner trust's debt to its lenders at the expiration of the leaseback. If we do not purchase the interest and the owner trust requests, we are obligated to use our best efforts to sell the owner trust's interest in the unit at the end of the leaseback. Any sale proceeds would be credited against the payment we are obligated to make to the owner trust. If we are not able to sell the interest by the end of the leaseback, we must pay the owner trust the full amount of the required payment but we are entitled to be reimbursed out of the proceeds of the sale in excess of 20% of the value of the owner trust's interest at the time the lease was entered into in 1996, plus interest, if the facility is sold within the following 36 months.

Off-Balance Sheet Arrangements

Clover Unit 1

See "Significant Contingent Obligations—Clover Lease" above.

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. At December 31, 2015, we estimate that the fair value of our purchased power agreements, forward sales of agreements, and forward purchases of natural gas was between $1.4 billion and $1.5 billion. Approximately 21% of the fair value of this portfolio is estimable using observable market prices. The remaining 79% 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 79% 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, it is estimated 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 $30.5 million at December 31, 2015. 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 combustion turbine 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 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 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 2015, all of our outstanding long-term debt accrued interest at fixed rates.

We maintain a $500.0 million 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. We did not have any borrowings outstanding under this facility at December 31, 2015; however, the interest rate on any borrowings would have been 1.4%. At December 31, 2015, we had letters of credit in the amount of $8.2 million outstanding under this facility.

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. At December 31, 2015, $99.7 million, $45.8 million, and $0.2 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
INDEX

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, 2015, 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, 2015, 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 9, 2016

/s/ JACKSON E. REASOR	/s/ ROBERT L. KEES
Jackson E. Reasor	Robert L. Kees
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors of
Old Dominion Electric Cooperative

We have audited the accompanying consolidated balance sheets of Old Dominion Electric Cooperative as of December 31, 2015 and 2014, 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, 2015. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Old Dominion Electric Cooperative at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Richmond, Virginia

March 9, 2016

OLD DOMINION ELECTRIC COOPERATIVE
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2015 AND 2014

	2015	2014
	(in thousands)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 1,722,477	$ 1,690,555
Less accumulated depreciation	(821,947)	(784,215)
Net Property, plant, and equipment	900,530	906,340
Nuclear fuel, at amortized cost	15,720	19,376
Construction work in progress	541,323	171,953
Net Electric Plant	1,457,573	1,097,669
Investments:		
Nuclear decommissioning trust	145,715	145,822
Lease deposits	101,816	99,191
Unrestricted investments and other	7,093	7,049
Total Investments	254,624	252,062
Current Assets:		
Cash and cash equivalents	58,383	1,424
Accounts receivable	10,960	8,656
Accounts receivable–deposits	1,200	—
Accounts receivable–members	83,248	83,108
Fuel, materials, and supplies	63,829	64,154
Deferred energy	—	19,948
Prepayments and other	4,683	5,131
Total Current Assets	222,303	182,421
Deferred Charges:		
Regulatory assets	61,073	87,987
Other	12,846	18,603
Total Deferred Charges	73,919	106,590
Total Assets	$ 2,008,419	$ 1,638,742
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 390,976	$ 379,097
Non-controlling interest	5,704	5,687
Total Patronage capital and Non-controlling interest	396,680	384,784
Long-term debt	1,024,746	721,038
Revolving credit facility	—	86,000
Total Long-term debt and Revolving credit facility	1,024,746	807,038
Total Capitalization	1,421,426	1,191,822
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	109,887	96,702
Accounts payable–members	98,462	35,217
Accrued expenses	5,580	4,568
Deferred energy	27,835	—
Total Current Liabilities	270,056	164,779
Deferred Credits and Other Liabilities:		
Asset retirement obligations	118,200	104,936
Obligations under long-term lease	90,622	84,730
Regulatory liabilities	73,702	78,764
Other	34,413	13,711
Total Deferred Credits and Other Liabilities	316,937	282,141
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,008,419	$ 1,638,742

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, 2015, 2014, AND 2013

	2015	2014	2013
		(in thousands)	
Operating Revenues	$ 1,020,028	$ 951,576	$ 842,069
Operating Expenses:			
Fuel	159,917	213,528	133,592
Purchased power	494,909	518,814	463,159
Transmission	113,622	75,959	66,590
Deferred energy	47,783	(57,141)	(18,834)
Operations and maintenance	49,768	49,599	41,546
Administrative and general	37,448	40,279	42,385
Depreciation and amortization	45,168	42,049	42,346
Amortization of regulatory asset/(liability), net	9,496	5,838	6,310
Accretion of asset retirement obligations	4,695	3,870	3,980
Taxes, other than income taxes	8,269	8,256	8,405
Total Operating Expenses	971,075	901,051	789,479
Operating Margin	48,953	50,525	52,590
Other expense, net	(3,339)	(3,086)	(2,562)
Gain/(loss) on investments, net	—	—	2,269
Investment income	5,519	7,349	5,333
Interest income on North Anna Unit 3 cost recovery	6,393	—	—
Interest charges, net	(45,627)	(45,693)	(47,680)
Income taxes	(3)	1	(143)
Net Margin including Non-controlling interest	11,896	9,096	9,807
Non-controlling interest	(17)	4	(234)
Net Margin attributable to ODEC	11,879	9,100	9,573
Patronage Capital - Beginning of Year	379,097	369,997	360,424
Patronage Capital - End of Year	$ 390,976	$ 379,097	$ 369,997

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, 2015, 2014, AND 2013

	2015	2014	2013
		(in thousands)	
Operating Activities:			
Net Margin including Non-controlling interest	$ 11,896	$ 9,096	$ 9,807
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	45,168	42,049	42,346
Other non-cash charges	18,706	17,766	18,604
Amortization of lease obligations	5,893	5,503	5,141
Interest on lease deposits	(2,910)	(2,841)	(2,774)
Change in current assets	(2,871)	(2,224)	(3,060)
Change in deferred energy	47,783	(57,141)	(18,834)
Change in current liabilities	62,694	9,204	(20,555)
Change in regulatory assets and liabilities	26,968	(2,467)	(9,004)
Change in deferred charges-other and deferred credits and other liabilities-other	5,973	(2,096)	(1,564)
Net Cash Provided by Operating Activities	219,300	16,849	20,107
Investing Activities:			
Purchases of held to maturity securities	(130,293)	(3,931)	(112,454)
Proceeds from sale of held to maturity securities	130,240	21,746	143,605
Increase in other investments	(4,726)	(6,760)	(7,468)
Electric plant additions	(373,516)	(135,857)	(32,093)
Net Cash Used for Investing Activities	(378,295)	(124,802)	(8,410)
Financing Activities:			
Issuance of long-term debt	332,000	—	100,000
Debt issuance costs	(1,754)	—	(744)
Payments of long-term debt	(28,292)	(28,292)	(88,827)
Dividend - non-controlling interest	—	—	(7,800)
Draws on revolving credit facility	104,000	387,604	—
Repayments on revolving credit facility	(190,000)	(301,604)	—
Net Cash Provided by Financing Activities	215,954	57,708	2,629
Net Change in Cash and Cash Equivalents	56,959	(50,245)	14,326
Cash and Cash Equivalents - Beginning of Year	1,424	51,669	37,343
Cash and Cash Equivalents - End of Year	$ 58,383	$ 1,424	$ 51,669

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 at December 31, 2015 and December 31, 2014. The income taxes reported on our Consolidated Statements of Revenues, Expenses, and Patronage Capital relate to the tax provision for TEC. As TEC is 100% owned by our Class A members, its equity is presented as a non-controlling interest in 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, TEC, a taxable corporation, is owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. Our rates are not regulated by the public service commissions of the states in which our member distribution cooperatives operate, but are set periodically by a formula that was accepted for filing by FERC.

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 conduct depreciation studies approximately every five years and our depreciation rates were as follows:

	Depreciation Rates		
Generating Facility	2015	2014	2013
Clover	1.8%	1.8%	1.8%
North Anna	3.0	3.0	3.0
Louisa	3.5	3.5	3.5
Marsh Run	3.2	3.2	3.2
Rock Springs	3.3	3.3	3.3

Our last depreciation study was performed in 2011. Our next depreciation study is scheduled for 2016 to be implemented in 2017.

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, 2016. We continue to recognize receivables for certain spent nuclear fuel-related costs that we believe are probably of recovery from the DOE. At December 31, 2015 and 2014, we had an outstanding receivable of $4.3 million and $3.3 million, respectively.

Fuel, Materials, and Supplies

Fuel, materials, and supplies is primarily comprised of fuel and spare parts for our generating assets. Fuel, which consists primarily of coal and No. 2 fuel oil, is recorded at cost. Spare parts for our generating assets are recorded at cost.

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 2015, 2014, and 2013, was $13.8 million, $0.9 million, and $0.2 million, respectively.

Income Taxes

As a not-for-profit electric cooperative, we 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, 2015, 2014, and 2013.

Operating Revenues

Our operating revenues are derived from sales to our members and non-members and are recorded when power, including renewable energy credits, is delivered. We sell energy to our Class A members pursuant to long-term wholesale power contracts that we maintain with each of our member distribution cooperatives. These wholesale power contracts obligate each member distribution cooperative to pay us for power furnished in accordance with our rates. For the years ended December 31, 2015, 2014, and 2013, revenue from sales to our member distribution cooperatives, including the sale of renewable energy credits, was $968.9 million, $908.0 million, and $810.1 million, respectively. For the years ended December 31, 2015, 2014, and 2013, the sale of renewable energy credits included in revenue from sales to our member distribution cooperatives was $2.2 million, $1.3 million, and $1.4 million, respectively. See Note 5—Wholesale Power Contracts.

We sell excess purchased and generated energy, if any, to TEC, our Class B member, or to 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 2015, 2014, and 2013, 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. For the years ended December 31, 2015, 2014, and 2013, energy sales to non-members, including the sale of renewable energy credits, were $51.1 million, $43.5 million, and $31.9 million, respectively. For the years ended December 31, 2015, 2014, and 2013, the sale of renewable energy credits included in energy sales to non-members was $8.5 million, $5.9 million, and $6.1 million, respectively.

Formula Rate

Our power sales are comprised of two power products – energy and demand. Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as demand.

The rates we charge our member distribution cooperatives for sales of energy and demand are determined by a formula rate accepted by FERC which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

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

Energy costs, which are primarily variable costs, such as nuclear, coal, and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate rates, the base energy rate and the energy adjustment rate. Through December 31, 2013, the base energy rate was a fixed rate that required FERC approval prior to adjustment. To the extent the base energy rate over- or under-collected our energy costs, we credited or charged the difference through an energy adjustment rate. We reviewed our energy costs at least every six months to determine whether the base energy rate and the current energy adjustment rate together were recovering our actual and anticipated energy costs and revised the energy adjustment rate accordingly. Effective January 1, 2014, pursuant to FERC's acceptance of revisions to the formula rate as issued in FERC's December 2, 2013 order, the base energy rate is no longer a fixed rate that requires FERC approval prior to adjustment. The base energy rate now is developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the energy adjustment rate will be zero. With board approval, we can revise the energy adjustment rate at any time during the year if it becomes apparent that the combined base energy rate and the current energy adjustment rate are over-collecting or under-collecting our actual and anticipated energy costs. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part 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. Through December 31, 2013, we collected our total demand costs through a single demand rate. Effective January 1, 2014, pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order, we now collect our total demand costs through the following three separate rates:

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

As stated above, our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. We establish our demand rates to produce a net margin attributable to ODEC equal to 20% of our budgeted total interest charges plus additional equity contributions approved by our board of directors. Through December 31, 2013, utilizing Margin Stabilization, we adjusted our operating revenues to reflect actual demand costs incurred, including a net margin attributable to ODEC equal to 20% of actual interest charges plus additional equity contributions approved by our board of directors. Effective January 1, 2014:

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

For the years ended December 31, 2015 and 2013, we recorded a reduction in operating revenues of $9.6 million and $9.8 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges. For the year ended December 31, 2014, we did not record an adjustment to operating revenues utilizing Margin Stabilization, since the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equaled 19.5% of our actual total interest charges. See "Critical Accounting Policies—Margin Stabilization" above.

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 under 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.

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 and the revolving credit facility totaled $7.6 million and $6.7 million at December 31, 2015 and 2014, respectively, and are included 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 the revolving credit facility, and are included in interest charges, net.

Deferred Charges – Other

Deferred charges – other, includes unamortized debt issuance costs, the deferred rent related to the Wildcat Point operating lease, NYMEX margin mark-to-market asset, and the long-term portion of the prepayment of premiums on an insurance policy related to Wildcat Point.

Deferred Credits and Other Liabilities – Other

Deferred credits and other liabilities – other, includes NYMEX margin mark-to-market liability, Wildcat Point retainage, a gain on a long-term lease transaction (see Note 8—Long-term Lease Transaction), and liabilities associated with benefit plans for certain executives.

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. At December 31, 2015, we had an over-collected deferred energy balance of $27.8 million. To address the over-collection of energy costs, we decreased our total energy rate 2.9% effective July 2015 and also 5.4% effective January 1, 2016. At December 31, 2014, we had an under-collected deferred energy balance of $19.9 million.

Under-collected energy costs appear as an asset on our Consolidated Balance Sheet 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 on our Consolidated Balance Sheet and will be returned to our member distribution cooperatives in subsequent periods through our formula rate.

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 the operation of our combustion turbine facilities. 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 asset or regulatory liability, respectively, in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses, and Patronage Capital 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, 2015, 2014, or 2013.

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 and our syndicated credit agreement. See Note 11—Long-term Debt for discussion of the restrictions contained in the Indenture.

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 $83.2 million and $83.1 million, at December 31, 2015 and 2014, 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 to in exchange for those goods or services. We plan to adopt this standard for the fiscal year beginning January 1, 2018, and do not anticipate any changes in the presentation of revenue.

In April 2015, the FASB issued Accounting Standards Update 2015-03 Interest-Imputation of Interest (Subtopic 835-30). This update requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. We currently present debt issuance costs as an asset in deferred charges-other on our Consolidated Balance Sheet. We plan to adopt this standard for the fiscal year beginning January 1, 2016.

In May 2015, the FASB issued Accounting Standards Update 2015-07 Fair Value Measurement (Topic 820). This update affects the presentation of investments for which fair value is measured at net asset value per share (or its equivalent). We are currently evaluating the impact of this pronouncement on the presentation of the fair value of our nuclear decommissioning trust. We plan to adopt this standard for the fiscal year beginning January 1, 2016.

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 for 2015:

	Clover	North Anna	Combustion Turbine Facilities	Wildcat Point	Other	Total
			(in thousands)			
Property, plant, and equipment	$ 689,526	$ 355,667	$ 588,285	$ —	$ 88,999	$ 1,722,477
Accumulated depreciation	(361,339)	(198,752)	(237,493)	—	(24,363)	(821,947)
Net Property, plant, and equipment	328,187	156,915	350,792	—	64,636	900,530
Nuclear fuel, at amortized cost	—	15,720	—	—	—	15,720
Construction work in progress	16,750	32,209	48	488,700	3,616	541,323
Net Electric Plant	$ 344,937	$ 204,844	$ 350,840	$ 488,700	$ 68,252	$ 1,457,573

Our net electric plant is composed of the following for 2014:

	Clover	North Anna	Combustion Turbine Facilities	Wildcat Point	Other	Total
			(in thousands)			
Property, plant, and equipment	$ 678,006	$ 351,636	$ 587,955	$ —	$ 72,958	$ 1,690,555
Accumulated depreciation	(352,271)	(190,317)	(218,020)	—	(23,607)	(784,215)
Net Property, plant, and equipment	325,735	161,319	369,935	—	49,351	906,340
Nuclear fuel, at amortized cost	—	19,376	—	—	—	19,376
Construction work in progress	11,364	33,580	—	115,779	11,230	171,953
Net Electric Plant	$ 337,099	$ 214,275	$ 369,935	$ 115,779	$ 60,581	$ 1,097,669

We hold a 50% undivided ownership interest in Clover, a two-unit, 874 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 in our consolidated financial statements in accordance with proportionate consolidation accounting. At December 31, 2015 and 2014, we had an outstanding accounts payable balance of $8.7 million and $11.4 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, 1,897 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 in our consolidated financial statements in accordance with proportionate consolidation accounting. At December 31, 2015 and 2014, we had an outstanding accounts payable balance of $3.1 million due to Virginia Power for the operation, maintenance, and capital investment at North Anna.

We own three combustion turbine facilities that are carried at cost, less accumulated depreciation. We also own 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 constructing, and will be the sole owner of, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We had a ground lease related to land and land rights associated with Wildcat Point that was being accounted for as an operating lease. During 2015, we purchased the land and these land rights from EP for $40.0 million. Prior to entering into the agreement to purchase 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 that will be amortized through May 31, 2017. The balance of this regulatory asset as of December 31, 2015, was $3.1 million. As a result of the purchase of the land and land rights, we currently anticipate that the project cost will be approximately $834.3 million, including capitalized interest. To fund a portion of the project cost, on January 15, 2015, we issued $332.0 million of first mortgage bonds in a private placement transaction. See Note 12—Liquidity Resources.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators and one Alstom steam turbine generator. Beginning in June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. For 2015, 2014, and 2013, we expensed $2.3 million, $4.5 million, and $7.7 million, respectively, of non-capital costs related to Wildcat Point, which were recorded in administrative and general expense. Through December 31, 2015, we capitalized construction costs related to Wildcat Point totaling $488.7 million, including $12.6 million of capitalized interest.

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 by 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, 2015 and 2014, North Anna's nuclear decommissioning asset retirement obligation totaled $97.6 million and $93.7 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, is the primary driver 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 December 2014, the EPA issued the final rule regulating the disposal of CCRs, commonly known as coal ash. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act. The final rule was published in the Federal Register in April 2015 and, as a result, we established asset retirement obligations totaling $8.6 million during the second quarter of 2015.

In 2014, we established two asset retirement obligations for Clover ash landfills and also determined that we no longer had an asset retirement obligation for a waste pond for Clover.

The following represents changes in our asset retirement obligations for the years ended December 31, 2015 and 2014 (in thousands):

Asset retirement obligation at December 31, 2013	$ 80,860
Accretion expense	3,870
Increase in asset retirement obligations - new layer	17,953
Additional asset retirement obligations, net	2,253
Asset retirement obligations at December 31, 2014	$ 104,936
Accretion expense	4,695
Additional asset retirement obligations	8,569
Asset retirement obligation at December 31, 2015	$ 118,200

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 in 2003, 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.

NOTE 4—Power Purchase Agreements

In 2015, 2014, and 2013, our owned generating facilities together furnished approximately 43.0%, 40.2%, and 39.4%, 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 purchase 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. At December 31, 2015, due to changes in energy prices, we posted cash collateral of $1.2 million with our counterparties pursuant to contracts we had in place with them. At December 31, 2014, we were not required to post collateral with our counterparties. Additionally, at December 31, 2015 and 2014, we were required to post a letter of credit in the amount of $8.0 million and $10.0 million, respectively, to PJM.

Our purchased power costs for 2015, 2014, and 2013 were $494.9 million, $518.8 million, and $463.2 million, respectively.

As of December 31, 2015, our energy and capacity purchase obligations under the various agreements were as follows:

Year Ending December 31,	Energy and Capacity Obligations
	(in millions)
2016	$ 245.0
2017	161.7
2018	173.0
	$ 579.7

NOTE 5—Wholesale Power Contracts

We have a wholesale power contract with each of our eleven member distribution cooperatives. The wholesale power contracts are "all-requirements" contracts. 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, to the extent that we have the power and facilities available to do so. These contracts are effective until January 1, 2054, and beyond this date unless either party gives the other at least three years notice of termination.

An exception to the all-requirements obligations of the member distribution cooperatives relates to the ability of our eight mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from SEPA. Purchases under this exception constituted approximately 1.4% of our member distribution cooperatives' total energy requirements in 2015.

Two additional exceptions to the all-requirements nature of the contract permit the member distribution cooperatives to receive up to the greater of 5% of their power requirements or 5 MW from owned generation or other suppliers, and to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. In 2015, our member distribution cooperatives collectively received 9 MW under these exceptions. Beginning in the second quarter of 2016, we currently anticipate that our member distribution cooperatives will collectively receive approximately 60 MW under this exception. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formula rate. 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. 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,		
	2015	**2014**	**2013**
		(in millions)	
Rappahannock Electric Cooperative	$ 334.2	$ 311.7	$ 275.9
Shenandoah Valley Electric Cooperative	181.0	172.1	150.4
Delaware Electric Cooperative, Inc.	114.0	106.8	94.7
Choptank Electric Cooperative, Inc.	83.8	80.2	72.1
Southside Electric Cooperative	76.5	70.2	64.5
A&N Electric Cooperative	55.5	53.0	47.8
Mecklenburg Electric Cooperative	47.4	43.8	39.7
Prince George Electric Cooperative	25.4	23.5	21.6
Northern Neck Electric Cooperative	23.4	21.3	19.5
Community Electric Cooperative	16.6	15.3	13.9
BARC Electric Cooperative	11.1	10.1	10.0
Total	$ 968.9	$ 908.0	$ 810.1

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, 2015 and 2014:

	December 31, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)			
Nuclear decommissioning trust [1][2]	$ 145,715	$ 46,051	$ 99,664	$ —
Unrestricted investments and other [3]	211	—	211	—
Total Financial Assets	$ 145,926	$ 46,051	$ 99,875	$ —
Derivatives - gas and power [4]	$ 3,653	$ 3,653	$ —	$ —
Total Financial Liabilities	$ 3,653	$ 3,653	$ —	$ —

	December 31, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)			
Nuclear decommissioning trust [1][2]	$ 145,822	$ 45,573	$ 100,249	$ —
Unrestricted investments and other [3]	198	—	198	—
Total Financial Assets	$ 146,020	$ 45,573	$ 100,447	$ —
Derivatives - gas and power [4]	$ 5,215	$ 5,215	$ —	$ —
Total Financial Liabilities	$ 5,215	$ 5,215	$ —	$ —

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

(2) Nuclear decommissioning trust includes investments that are available for sale and classified as Level 2. These Level 2 assets consist of an equity fund that attempts to replicate the return of the S&P 500, an equity fund that invests in small capitalization stocks, and an equity fund that invests in international stocks. The fair values of the investments in the nuclear decommissioning trust have been estimated using the net asset value per share.

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

(4) Derivatives – gas and power represent natural gas futures contracts which are recorded on our Consolidated Balance Sheet in deferred credits and other liabilities–other, and which are indexed against NYMEX. 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:

Commodity	Unit of Measure	Quantity as of December 31, 2015	2014
Natural Gas	MMBTU	10,620,000	5,610,000

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, 2015	2014
		(in thousands)	
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 3,653	$ 5,215
Total derivatives in a liability position		$ 3,653	$ 5,215

The Effect of Derivative Instruments on the Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Years Ended December 31, 2015 and 2014

Derivatives Accounted for Utilizing Regulatory Accounting	**Amount of Gain (Loss) Recognized in Regulatory Asset/ Liability for Derivatives as of December 31,**		**Location of Gain (Loss) Reclassified from Regulatory Asset/ Liability into Income**	**Amount of Gain (Loss) Reclassified from Regulatory Asset/ Liability into Income for the Year Ended December 31,**	
	2015	**2014**		**2015**	**2014**
	(in thousands)			(in thousands)	
Natural gas futures contracts [1]	$ (3,694)	$ (5,497)	Fuel	$ (6,653)	$ (1,170)
Purchased power contracts	—	—	Purchased power	(14)	—
Purchased power contracts - excess sales	—	—	Operating revenues	—	90
Total	$ (3,694)	$ (5,497)		$ (6,667)	$ (1,080)

[1] As of December 31, 2015 and 2014, includes a regulatory liability of $41 thousand and $0.3 million, respectively, to be recognized in future periods as the result of the contracts being effectively settled.

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 is being amortized into income ratably over the 21.8 year operating lease term, as a reduction to depreciation and amortization expense. At December 31, 2015 and 2014, the unamortized portion of the deferred gain was $2.2 million and $3.2 million, respectively.

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. The payment undertaking agreement, which had a balance of $307.3 million at December 31, 2015, is issued by Rabobank, which has senior debt obligations which are currently rated "A+" by S&P and "Aa2" by Moody's. The amount of debt considered to be extinguished by in substance defeasance was $307.3 million and $308.5 million, at December 31, 2015 and 2014, respectively.

At the end of the term of the leaseback, we have three options: (1) retain possession of the interest in the unit by paying a fixed purchase price to the owner trust, (2) return possession of the interest to the owner trust and arrange for an acceptable third-party to enter into a power purchase agreement with the owner trust, or (3) return possession of the interest and pay a termination amount to the owner trust.

NOTE 9—Investments

Investments were as follows at December 31, 2015 and 2014:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
				(in thousands)		
December 31, 2015						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 42,898	$ 2,940	$ —	$ 45,838	$ 45,838
Equity securities	Available for sale	72,213	29,164	(1,713)	99,664	99,664
Cash and other	Available for sale	213	—	—	213	213
Total Nuclear Decommissioning Trust		$ 115,324	$ 32,104	$ (1,713)	$ 145,715	$ 145,715
Lease Deposits [2]						
Government obligations	Held to maturity	$ 101,816	$ 4,428	$ —	$ 106,244	$ 101,816
Total Lease Deposits		$ 101,816	$ 4,428	$ —	$ 106,244	$ 101,816
Unrestricted investments						
Government obligations	Held to maturity	$ 2,003	$ —	$ (2)	$ 2,001	$ 2,003
Debt securities	Held to maturity	2,689	—	(5)	2,684	2,689
Total Unrestricted Investments		$ 4,692	$ —	$ (7)	$ 4,685	$ 4,692
Other						
Equity securities	Trading	$ 175	$ 36	$ —	$ 211	$ 211
Non-marketable equity investments	Equity	2,190	1,978	—	4,168	2,190
Total Other		$ 2,365	$ 2,014	$ —	$ 4,379	$ 2,401
						$ 254,624
December 31, 2014						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 41,654	$ 3,516	$ —	$ 45,170	$ 45,170
Equity securities	Available for sale	68,259	31,990	—	100,249	100,249
Cash and other	Available for sale	403	—	—	403	403
Total Nuclear Decommissioning Trust		$ 110,316	$ 35,506	$ —	$ 145,822	$ 145,822
Lease Deposits [2]						
Government obligations	Held to maturity	$ 99,191	$ 5,569	$ —	$ 104,760	$ 99,191
Total Lease Deposits		$ 99,191	$ 5,569	$ —	$ 104,760	$ 99,191
Unrestricted investments						
Government obligations	Held to maturity	$ 2,005	$ —	$ —	$ 2,005	$ 2,005
Debt securities	Held to maturity	2,636	—	(18)	2,618	2,636
Total Unrestricted Investments		$ 4,641	$ —	$ (18)	$ 4,623	$ 4,641
Other						
Equity securities	Trading	$ 151	$ 47	$ —	$ 198	$ 198
Non-marketable equity investments	Equity	2,210	1,821	—	4,031	2,210
Total Other		$ 2,361	$ 1,868	$ —	$ 4,229	$ 2,408
						$ 252,062

(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 related to assets held in the nuclear decommissioning trust are deferred as a regulatory asset or liability, respectively.

(2) Investments in lease deposits are restricted for the use of funding our future lease obligations. See Note 8—Long-term Lease Transaction.

Our investments by classification at December 31, 2015 and 2014, were as follows:

Description	December 31, 2015 Cost	December 31, 2015 Carrying Value	December 31, 2014 Cost	December 31, 2014 Carrying Value
		(in thousands)		
Available for sale	$ 115,324	$ 145,715	$ 110,316	$ 145,822
Held to maturity	106,508	106,508	103,832	103,832
Equity	2,190	2,190	2,210	2,210
Trading	175	211	151	198
	$ 224,197	$ 254,624	$ 216,509	$ 252,062

Contractual maturities of debt securities at December 31, 2015, 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)]	$ —	$ —	$ 45,838	$ —	$ 45,838
Held to maturity	1,239	105,269	—	—	106,508
	$ 1,239	$ 105,269	$ 45,838	$ —	$ 152,346

(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 at December 31, 2015 and 2014, were as follows:

	December 31, 2015	December 31, 2014
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	$ 13,706	$ 15,571
Deferred asset retirement costs	330	346
NOVEC contract termination fee	31,809	34,256
Loan acquisition fee	447	671
Interest rate hedge	2,544	2,710
North Anna Unit 3	—	22,748
Voluntary prepayment to NRECA Retirement Security Plan	5,415	6,188
Deferred net unrealized losses on derivative instruments	3,694	5,497
Wildcat Point lease termination	3,128	—
Total Regulatory Assets	$ 61,073	$ 87,987
Regulatory Assets included in Current Assets:		
Deferred energy	$ —	$ 19,948
Regulatory Liabilities:		
North Anna asset retirement obligation deferral	$ 42,845	$ 42,733
North Anna nuclear decommissioning trust unrealized gain	30,391	35,506
Unamortized gains on reacquired debt	466	525
Total Regulatory Liabilities	$ 73,702	$ 78,764
Regulatory Liabilities included in Current Liabilities:		
Deferred energy	$ 27,835	$ —

The regulatory assets will be recognized as expenses concurrent with their recovery through rates and the regulatory liabilities will be recognized as a reduction 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 will be amortized ratably over the remaining life of the lease and will be fully amortized in 2018.
- 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.
- North Anna Unit 3. In February 2011, we made the determination not to participate in North Anna Unit 3 and on December 16, 2011, we finalized our withdrawal as a participant in the project and transferred our interest to Virginia Power. Related to this decision, in 2011 we reclassified the corresponding construction work in progress to a regulatory asset. Following the 2015 approval by the VSCC of the recovery of 70% of North Anna Unit 3 costs in Virginia Power's rate case, we received a payment of $22.5 million, consisting of $16.1 million of our regulatory asset plus $6.4 million of interest income on these costs. Our board approved the amortization of the remaining balance of $6.6 million in 2015. The amortization is recorded in amortization of regulatory asset/(liability), net on the Consolidated Statements of Revenues, Expenses, and Patronage capital.
- 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. On June 22, 2015, we reached an agreement to purchase this land and these land rights from Essential Power, LLC for $40.0 million and on November 19, 2015, the transaction closed and title transferred to us. Prior to entering into the agreement to purchase 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 that will be amortized through 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 charged to our members 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.

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 members in subsequent periods.

NOTE 11—Long-term Debt

Long-term debt consists of the following:

	December 31,	
	2015	**2014**
	(in thousands)	
$260,000,000 principal amount of First Mortgage Bonds, 2015 Series A due 2044 at an interest rate of 4.46%	$ 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	—
$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%	75,000	78,000
$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%	83,125	85,500
$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	135,413	145,830
$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	162,500	175,000
	1,053,038	749,330
Current maturities	(28,292)	(28,292)
	$ 1,024,746	$ 721,038

At December 31, 2015 and 2014, deferred gains and losses on reacquired debt totaled a net loss of approximately $13.2 million and $15.0 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)
2016	$ 28,292
2017	28,292
2018	28,292
2019	28,292
2020	28,292
2021 and thereafter	911,578
	$ 1,053,038

The aggregate fair value of long-term debt was $1,123.7 million and $847.7 million at December 31, 2015 and 2014, 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 issued 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.

Our 2002 Series A Bonds, with an aggregate principal amount of $60.2 million outstanding, were subject to optional redemption by ODEC on or after June 1, 2013. We issued a call notice for the 2002 Series A Bonds in the second quarter of 2013 and redeemed these bonds on June 1, 2013. We paid a premium of $0.3 million and had unamortized debt issuance costs of $1.5 million related to these bonds, for a total of $1.8 million. These costs have been deferred as a regulatory asset and will be amortized over the original life of the debt to 2028.

On June 28, 2013, we issued $100.0 million of first mortgage bonds in a private placement transaction. The issuance consisted of $50.0 million of 4.21% First Mortgage Bonds, 2013 Series A due December 1, 2043 and $50.0 million of 4.36% First Mortgage Bonds, 2013 Series B due December 1, 2053.

On January 15, 2015, we issued $332.0 million of first mortgage bonds in a private placement transaction. The issuance consisted of $260.0 million of 4.46% First Mortgage Bonds, 2015 Series A due December 1, 2044, and $72.0 million of 4.56% First Mortgage Bonds, 2015 Series B due December 1, 2053.

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

NOTE 12—Liquidity Resources

We maintain a $500.0 million revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019. We did not have any borrowings outstanding under this facility at December 31, 2015; however, the interest rate on any borrowings would have been 1.4%. At December 31, 2015, we had letters of credit in the amount of $8.2 million outstanding. At December 31, 2014, we had $86.0 million in borrowings outstanding under this facility at an interest rate of 1.5% and a $10.0 million letter 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). We are in compliance with the credit agreement. Obligations under the credit agreement may be accelerated following, among other things, (1) the failure to pay outstanding principal when due or other amounts, including interest, within five days after the due date, (2) a material misrepresentation, (3) a cross-payment default or cross-acceleration under specified indebtedness, (4) failure by us to perform any obligation relating to the credit agreement following, in some cases, specified cure periods, (5) bankruptcy or insolvency events, (6) invalidity of the credit agreement and related loan documentation or our assertion of invalidity, and (7) 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 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 totaled $88.9 million and $35.2 million at December 31, 2015 and 2014, respectively. Amounts extended by our member distribution cooperatives are included in accounts receivable-members and totaled $7.8 million at December 31, 2015, and were zero at December 31, 2014.

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 Internal Revenue Code. 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, 2015 and 2014, 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 a 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 pension restoration plan totaled $2.5 million in 2015, $2.4 million in 2014, and $2.2 million in 2013. 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 2015. Pension expense, inclusive of administrative fees, was $3.4 million, $3.3 million, and $3.0 million for 2015, 2014, and 2013, respectively. Pension expense for 2015, 2014, and 2013 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 $231,000, $224,000, and $206,000 in 2015, 2014, and 2013, respectively.

NOTE 14—Other

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. We have not recorded a receivable related to this matter and are evaluating our next steps.

Clean Power Plan

On October 23, 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 establishes 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 EPA also published proposed Federal Plan and Model Rules, which are expected to be finalized in early summer 2016. Under the final Clean Power Plan, states must submit a single State Implementation Plan (SIP) by September 2016, or a multi-state plan by September 2017. The SIP will need to address, among other things, the inclusion of new units in the goals, the treatment of nuclear units, and the selection of a rate-based or mass-based program. In addition, the SIP must propose methods of achieving emissions reduction goals, which may include increasing efficiency of existing fossil-fuel plants, increasing energy conservation, and increasing renewable and other non-emitting energy technologies. The items the SIP will need to address will be very important in understanding how the Clean Power Plan will affect us.

The primary court 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. We are monitoring the litigation, and are utilizing stakeholder processes to engage the state agencies charged with developing the state plans. We currently cannot predict the impact of the Clean Power Plan on our existing facilities due to the complexities of this rulemaking and the ongoing litigation.

Subsequent Event

In March 2016, our Board of Directors approved a decrease to our total energy rate of approximately 6.8%, effective April 1, 2016. This decrease was implemented due to changes in our realized as well as projected energy costs.

NOTE 15—Supplemental Cash Flows Information

Cash paid for interest, net of amounts capitalized, in 2015, 2014, and 2013, was $42.0 million, $43.1 million, and $44.3 million, respectively. Cash paid for income taxes was immaterial in 2015, 2014, and 2013. Significant accrued capital expenditures in 2015 and 2014, was $38.1 million and $33.3 million, respectively. Significant accrued capital expenditures was immaterial for 2013.

NOTE 16—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 or environmental regulations. 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 $13.5 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and allows for an inflationary provision adjustment every five years. 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 $33.3 million at December 31, 2015.

NOTE 17—Selected Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years 2015 and 2014 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					
2015					
Operating Revenues	$ 292,256	$ 249,341	$ 254,265	$ 224,166	$ 1,020,028
Operating Margin	15,193	14,214	13,297	6,249	48,953
Net Margin attributable to ODEC	2,894	2,992	3,005	2,988	11,879
2014					
Operating Revenues	$ 265,096	$ 217,331	$ 233,904	$ 235,245	$ 951,576
Operating Margin	12,194	13,121	13,015	12,195	50,525
Net Margin attributable to ODEC	2,310	2,330	2,349	2,111	9,100

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 President and CEO, and Senior Vice President and CFO conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and CEO, and 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 comprised of members from senior and middle management to assist in this evaluation. There have been no significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls 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, 2015, 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, 2015, 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 comprised 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

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

Inherent Limitations on Internal Control

There are inherent limitations 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 each year, 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 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 at our annual meeting. 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, 2015, including principal occupation and employment during the past five years, qualifications, and directorships in public corporations, if any, is listed below. A&N Electric Cooperative currently has an interim CEO, and as such, only has one representative on our board at this time.

J. William Andrew, Jr. (62). 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 (70). 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.

Darlene H. Carpenter (69). Realtor of Century 21 New Millennium since 2013. Ms. Carpenter was a Realtor of 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. (72). 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 (64). 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 (52). 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 (58). 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.

Fred C. Garber (71). 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. (70). 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 (54). 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 and was Executive Vice President and General Manager of Pioneer Electric Cooperative from 2006 to 2011. Mr. Harmon has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2013.

Bruce A. Henry (70). 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 (67). 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 (39). CEO and General Manager of BARC Electric Cooperative since 2010. Mr. Keyser was CEO and General Counsel for American Samoa Power Authority from 2006 to 2010. Mr. Keyser has held executive positions in the utility industry since 2006 and has been a director of ODEC since 2010.

John C. Lee, Jr. (55). 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 (39). 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.

Paul E. Owen (65). Retired, formerly Director of Business Management with Smithfield Deli Group from 1974 to 2010. Mr. Owen has been a director of ODEC since 2006 and a director of Community Electric Cooperative since 2000.

Myron D. Rummel (63). President and CEO of Shenandoah Valley Electric Cooperative since 2005. Mr. Rummel has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2005.

Keith L. Swisher (61). 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 (60). President and CEO of Choptank Electric Cooperative, Inc. since 2011. Mr. Wheatley was Senior Vice President Corporate Services of Choptank Electric Cooperative, Inc. from 2002 to 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 (63). 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.

Carl R. Widdowson (77). Self-employed farmer since 1956. Mr. Widdowson has been a director of ODEC since 1987 and a director of Choptank Electric Cooperative, Inc. since 1980.

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 at December 31, 2015, their respective ages, positions and relevant business experience are listed below.

Jackson E. Reasor (63). President and CEO of ODEC and the VMDAEC, an electric cooperative association which provides services to its members and certain other electric cooperatives, since 1998.

Robert L. Kees (63). 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 (58). 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.

Elissa M. Ecker (56). Vice President of Human Resources since 2004.

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 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 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 of 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 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 50th percentile of the market. Intandem LLC has been engaged to create a performance appraisal instrument for the 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 CEO to the entire board of directors and the entire board of directors approves the compensation. Our board of directors has delegated to our 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 CEO, is approved by our CEO based upon market-based salary data. On an annual basis our board of directors reviews the performance and compensation of our CEO, and our CEO reviews the performance and compensation of the remaining executive officers.

Our CEO is also the CEO of the VMDAEC, and their board of directors also approves his compensation.

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. On an annual basis, our board of directors determines the bonus criteria for, and may award a bonus to, our CEO. On an annual basis, our CEO determines bonus criteria for, and may award a bonus to, the other executive officers.

Severance Benefits

We believe that companies should provide reasonable severance benefits to the CEO. With respect to our CEO, these severance benefits reflect the fact that it may be difficult to find comparable employment within a short period of time. Our CEO's contractual rights to amounts following severance are set forth in his employment agreement. None of our other executive officers have any contractual severance benefits.

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 2015, 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 2015 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 regulations. Currently, our board of directors has determined that our CEO is the only participant in this plan. We have made a $15,000 contribution to the plan each year for his benefit since the inception of the plan in 2006.

Pension Restoration Plan

We participate in a 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 CEO, 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 CEO receives during contract discussions with our CEO. The perquisite for Mr. Reasor is expenses for personal use of a company automobile which amounted to $6,359 in 2015 and $2,251 in 2014.

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 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	2015	$554,565	$ —	$ 61,882	$ 29,767	$ 646,214
President and CEO	2014	511,905	—	(27,731)	25,356	509,530
	2013	487,136	—	348,081	25,343	860,560
Robert L. Kees	2015 [3]	294,944	—	68,071	7,084	370,099
Senior Vice President and CFO	2014	286,353	—	(6,734)	6,841	286,460
	2013	278,013	—	245,777	6,455	530,245
D. Richard Beam [4]	2015	291,929	—	366,581	7,065	665,575
Senior Vice President of Power Supply	2014	278,426	—	20,747	6,652	305,825
	2013	228,824	—	169,437	5,667	403,928
Elissa M. Ecker	2015 [5]	201,656	—	103,956	5,178	310,790
Vice President of Human Resources	2014 [5]	201,656	—	11,897	5,068	218,621
	2013	195,783	—	89,934	5,016	290,733

(1) The values disclosed here represent the changes in the NRECA Retirement Security Plan value and the pension restoration plan.

(2) The items included in All Other Compensation are identified in the All Other Compensation table below. In prior years, All Other Compensation had included an allocated portion of premiums paid by us with respect to our obligation to fund our defined benefit plan, the NRECA Retirement Security Plan. 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 pension restoration plan benefits for each named executive officer.

(3) For 2015, salary includes a lump sum salary adjustment of $3,554.

(4) On November 5, 2013, we appointed Mr. D. Richard Beam as Senior Vice President of Power Supply effective November 16, 2013.

(5) For 2015, salary includes a lump sum salary adjustment of $3,692. For 2014, salary includes a lump sum salary adjustment of $5,873. Lump sum salary adjustments are not included in the calculation of pension benefits.

Employment Agreement

We have an employment agreement with our CEO. We do not have an employment agreement with any of our other executive officers or our controller.

On May 23, 2012, ODEC entered into an employment agreement with Jackson E. Reasor, our CEO. The agreement is for the term of three years, with an automatic one-year extension unless Mr. Reasor or ODEC and the VMDAEC (collectively, the "Employer") give written notice 30 days prior to the expiration of the agreement. The agreement provides that he will receive annual compensation of $493,500, effective June 1, 2012, subject to annual adjustment by the boards of directors of the Employer. The annual compensation includes amounts paid to the deferred compensation plan, which totaled $15,000 in 2015. The boards of directors of the Employer also may grant Mr. Reasor an annual bonus at their discretion. Mr. Reasor will also be entitled to participate in all benefit plans available to the employees of the Employer. The VMDAEC contributed $45,000 of Mr. Reasor's salary in 2015 and is expected to contribute the same amount in 2016.

Under the agreement, if Mr. Reasor voluntarily terminates his employment following material breach by the Employer or the Employer terminates him without specified cause, the Employer will pay Mr. Reasor a salary at the rate in effect on the date of termination for one year, plus medical insurance benefits, with limited exceptions. If the agreement is not continued at the end of the stated term, the Employer will pay Mr. Reasor a salary at the rate in effect on the date of termination for six months.

Where the termination is "without cause" or Mr. Reasor terminates employment for "good reason", the employment agreement provides for benefits equal to one year of base salary and medical insurance. However, if he becomes employed in any capacity during the one-year period immediately following the date of termination, the Employer's obligation to pay the base salary shall be reduced by the amount of his salary at the new employer. Also, the medical insurance benefit will cease if he becomes eligible for medical insurance coverage by virtue of his employment with another company. In addition, a terminated CEO is entitled to receive any benefits that he otherwise would have been entitled to receive under our 401(k) plan, pension plan and supplemental retirement plans, although those benefits are not increased or accelerated.

Based upon a hypothetical termination date of December 31, 2015, the severance benefits Mr. Reasor would have been entitled to would be as follows:

Annual compensation	$ 575,547
Targeted bonus	—
Medical insurance	17,308
Total	$ 592,855

Under our employment contract with Mr. Reasor, "cause" is defined as (1) gross incompetence, insubordination, gross negligence, willful misconduct in office or breach of a material fiduciary duty, which includes a breach of confidentiality; (2) conviction of a felony, a crime of moral turpitude or commission of an act of embezzlement or fraud against ODEC or the VMDAEC or any subsidiary or affiliate thereof; (3) the CEO's material failure to perform a substantial portion of his duties and responsibilities under the employment contract, but only after the Employer provides the CEO written notice of such failure and gives him 30 days to remedy the situation; or (4) deliberate dishonesty of the CEO with respect to ODEC or the VMDAEC or any of its subsidiaries or affiliates.

The CEO may terminate his employment with or without good reason by written notice to the boards of directors effective 60 days after receipt of such notice by the boards of directors. If the CEO terminates his employment for good reason, then the CEO is entitled to the salary specified above in the "without cause" paragraph. The CEO will not be required to render any further services. Upon termination of employment by the CEO without good reason, the CEO is not entitled to further compensation. Under our employment contract with Mr. Reasor, "good reason" is defined as the Employer's failure to maintain compensation and benefits or the Employer's material breach of any provision of the employment contract, which failure or breach continued for more than 30 days after the date on which the boards of directors received such notice.

Defined Benefit Plans

The following table lists the estimated values under the NRECA Retirement Security Plan and the pension restoration plan as of December 31, 2015. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits is limited to $265,000 effective January 1, 2016.

PENSION BENEFITS

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Year
Jackson E. Reasor	NRECA Retirement Security Plan	1.08	$ 61,882	$ 1,176,790
	Pension Restoration Plan	—	106,699 (1)	140,213
Robert L. Kees	NRECA Retirement Security Plan	1.00	68,071	1,720,052
	Pension Restoration Plan	—	—	20,390
D. Richard Beam	NRECA Retirement Security Plan	28.33	1,601,816	—
	Pension Restoration Plan	28.33	27,562	—
Elissa M. Ecker	NRECA Retirement Security Plan	10.08	444,681	—

(1) Beginning in 1998 through December 31, 2006, Mr. Reasor participated in a pension restoration severance pay plan and was the only participant in the plan. Mr. Reasor's accrued benefits under this plan were frozen and will be paid to Mr. Reasor upon termination of employment.

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 (3.04% for 2015, and 3.80% for 2014) and the PPA three segment yield rates (1.40%, 3.88%, and 4.96% for 2015, and 1.19%, 4.53%, and 5.66% for 2014) and the required Internal Revenue Service mortality table for lump sum payments (1994 GAS, projected to 2002, blended 50%/50% for unisex mortality in combination with the 30-year Treasury rates and PPA RP 2000 at 2015 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 pension restoration plan. In 2014, in accordance with the pension restoration plan, Mr. Reasor and Mr. Kees each received payment of their respective pension restoration plan benefits as of December 31, 2014. As long as Mr. Reasor and Mr. Kees continue to work for ODEC, they will continue to earn benefit credit and may elect to receive a payment of their respective pension restoration plan benefits.

Prior to the pension restoration plan, from 1998 through December 31, 2006, Mr. Reasor participated in a pension restoration severance pay 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. The amounts frozen are $45,852 and $60,817, respectively, for a total of $106,699. These amounts will be paid to Mr. Reasor upon termination of employment.

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, and Mr. Kees elected quasi-retirement effective January 31, 2015. Both Mr. Reasor and Mr. Kees continue to work for ODEC. The quasi-retirement benefit for Mr. Reasor was a lump sum cash distribution of $1,176,790 and was calculated based on a February 27, 2015 quasi-retirement date. The quasi-retirement benefit for Mr. Kees was a lump sum cash distribution of $1,720,052, and was calculated based on a January 15, 2015 quasi-retirement date. Mr. Reasor and Mr. Kees will continue to earn benefit credit for as long as they each continue to work after the quasi-retirement date. Once Mr. Reasor and Mr. Kees retire, they will receive a benefit for the time worked after the quasi-retirement date.

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 2015 and 2016, 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 severance of employment, whether upon termination, retirement, or death.

The following table sets forth the non-qualified deferred compensation paid to our executive officers in 2015:

NON-QUALIFIED DEFERRED COMPENSATION

Name	Executive Contributions in Last Fiscal Year	Registrant Contributions in Last Fiscal Year	Aggregate Gains in Last Fiscal Year	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End
Jackson E. Reasor	$ —	$ 15,000	$ (1,857)	$ —	$ 211,080
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

The following table sets forth information concerning all other compensation awarded to, earned by, or paid to these executives during the last completed fiscal year.

ALL OTHER COMPENSATION

Name	Perquisites and Other Personal Benefits(1)(2)	Company-paid Life Insurance	Total All Other Compensation
Jackson E. Reasor	$ 26,659	$ 3,108	$ 29,767
Robert L. Kees	5,300	1,784	7,084
D. Richard Beam	5,300	1,765	7,065
Elissa M. Ecker	3,959	1,219	5,178

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

(2) For Mr. Reasor, also includes $15,000 company contribution to the non-qualified deferred compensation plan and $6,359 for personal use of a company automobile.

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"). Our outside directors were compensated by a monthly retainer of $3,000. They 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. All directors are entitled to be reimbursed for out-of-pocket expenses incurred in attending meetings. 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 2015:

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash
Paul H. Brown	$ 36,750
Darlene H. Carpenter	36,750
Earl C. Currin, Jr.	36,750
E. Garrison Drummond	36,500
Fred C. Garber	36,750
Hunter R. Greenlaw, Jr.	38,750
Bruce A. Henry	38,750
David J. Jones	38,000
Paul E. Owen	36,750
Keith L. Swisher	36,750
Carl R. Widdowson	40,500
	$ 413,000

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 to the CEO. Our board of directors has delegated to our 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 CEO to the entire 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.

Myron D. Rummel, Chairman
J. William Andrew, Jr.
E. Garrison Drummond
Kent D. Farmer
Hunter R. Greenlaw, Jr.
David J. Jones

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.

	2015	2014
Audit Fees [(1)]	$ 315,747	$ 300,000
Audit-Related Fees [(2)]	—	—
Tax Fees [(3)]	12,498	16,626
Total	$ 328,245	$ 316,626

(1) Fees for professional services provided for the audit of ODEC's annual financial statements as well as reviews of ODEC's 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 2015 and 2014, 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 2015 and 2014, 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 42

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 May 12, 2015, as amended on May 12, 2015 (filed as exhibit 3 to the Registrant's Form 10-Q, File No. 000-50039, filed on May 13, 2015).

*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 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).

*10.2 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).

*10.3 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).

*10.4 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).

*10.5 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).

*10.6 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).

*10.7 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).

*10.8 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).

*10.9 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).

*, ***10.10 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 11, 2008).

*10.11 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).

*,**10.12 Participation Agreement, dated as of February 29, 1996, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein and Utrecht America Finance Co (filed as exhibit 10.35 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.13 Clover Unit 1 Equipment Interest Lease Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Equipment Head Lessor, and State Street Bank and Trust Company, as Equipment Head Lessee (filed as exhibit 10.36 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.14 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).

*,**10.15 Corrected Option Agreement to Lease, dated as of February 29, 1996, among Old Dominion Electric Cooperative and State Street Bank and Trust Company (filed as exhibit 10.38 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.16 Clover Agreements Assignment and Assumption Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Assignor, and State Street Bank and Trust Company, as Assignee (filed as exhibit 10.39 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.17 Payment Undertaking Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative and Cooperative Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch (filed as exhibit 10.42 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.18 Payment Undertaking Pledge Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Payment Undertaking Pledgor, and State Street Bank and Trust Company, as Payment Undertaking Pledgee (filed as exhibit 10.43 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.19 Pledge Agreement, dated as of February 29, 1996, between Old Dominion Electric Cooperative, as Pledgor, and State Street Bank and Trust Company, as Pledgee (filed as exhibit 10.44 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.20 Tax Indemnity Agreement, dated as of February 29, 1996, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein and Utrecht America Finance Co. (filed as exhibit 10.45 to the Registrant's Form 10-K for the year ended December 31, 1996, File No. 33-46795, on March 20, 1997).

*,**10.21 Amendment No. 3 to Participation Agreement (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*,**10.22 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).

*,**10.23 Amendment No. 2 to Corrected Foundation Operating Lease Agreement (filed as exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*,**10.24 Investment Agreement (filed as exhibit 10.4 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*,**10.25 Investment Pledge Agreement (filed as exhibit 10.5 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*,**10.26 Amendment No. 3 to Payment Undertaking Agreement (filed as exhibit 10.6 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*,**10.27 Amendment No. 2 to Tax Indemnity Agreement (filed as exhibit 10.7 to the Registrant's Form 10-Q for the quarter ended March 31, 2006, File No. 000-50039, on May 12, 2006).

*10.28 Employment Agreement, dated June 1, 2012, between Old Dominion Electric Cooperative and Jackson E. Reasor and accepted by Jackson E. Reasor on May 23, 2012 (filed as Exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on May 25, 2012).

*10.29 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).

*10.30 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).

*,**10.31 Amendment No. 1 to Participation Agreement, dated as of December 19, 2002, among Old Dominion Electric Cooperative, State Street Bank and Trust Company, the Owner Participant named therein, Utrecht America Finance Co and Cedar Hill International Corp.

*,**10.32 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.

*,**10.33 Amendment No. 1 to Corrected Foundation Operating Lease Agreement, dated as of December 19, 2002, between State Street Bank and Trust Company, as Foundation Lessor and Old Dominion Electric Cooperative, as Foundation Lessee.

*,**10.34 Amendment No. 2 to Payment Undertaking Agreement, dated as of December 19, 2002 between Old Dominion Electric Cooperative and Cooperatieve Centrale Raiffeisen Boerenleenbank B.A., "Rabobank Nederland", New York Branch.

*,**10.35 Amendment No. 1 to Tax Indemnity Agreement, dated as of December 19, 2002, between Old Dominion Electric Cooperative and the Owner Participant named therein.

*,**10.36 Amendment No. 2 to Participation Agreement, dated as of December 31, 2004, between and among Old Dominion Electric Cooperative, U.S. Bank National Association, Wachovia Bank, National Association, Utrecht-America Finance Co., and Cedar Hill International Corp. (filed as exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on January 13, 2005).

*10.37 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).

*10.38 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, 2008).

*10.39 Credit Agreement, dated as of November 21, 2011, 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 10.39 to the Registrant's Form 10-K for the year ended December 31, 2011, File No. 000-50039, on March 14, 2012).

*10.40 First amendment to Credit Agreement, dated as of March 12, 2014, 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 10-Q for the quarterly period ended March 31, 2014, File No. 000-50039, on May 9, 2014).

*10.41 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).

*10.42 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).

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).

23.1 Consent of Ernst & Young LLP

31.1 Certification of the Principal Executive Officer pursuant to Rule 13a-14(a)

31.2 Certification of the Principal Financial Officer pursuant to Rule 13a-14(a)

32.1 Certification of the Principal Executive Officer pursuant to 18 U.S.C. § 1350

32.2 Certification of the 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

* 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.

****XBRL information is furnished and not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

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/ JACKSON E. REASOR
Jackson E. Reasor
President and Chief Executive Officer

Date: March 9, 2016

Signature	Title
/s/ JACKSON E. REASOR Jackson E. Reasor	President and Chief Executive Officer (Principal executive officer)
/s/ ROBERT L. KEES Robert L. Kees	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/ 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/ FRED C. GARBER Fred C. Garber	Director
/s/ HUNTER R. GREENLAW, JR. Hunter R. Greenlaw, Jr.	Director
/s/ STEVEN A. HARMON Steven A. Harmon	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
Paul E. Owen	Director
/s/ MYRON D. RUMMEL Myron D. Rummel	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/ CARL R. WIDDOWSON Carl R. Widdowson	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 2015. Accordingly, ODEC will not file an annual report with the Securities and Exchange Commission.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

Richmond, VA

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-100577) of Old Dominion Electric Cooperative and in the related Prospectus of our report dated March 9, 2016, with respect to the consolidated financial statements of Old Dominion Electric Cooperative in this Annual Report (Form 10-K) for the year ended December 31, 2015.

/s/ Ernst & Young LLP

March 9, 2016

Exhibit 31.1

CERTIFICATIONS

I, Jackson E. Reasor, 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. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

(a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2016

/s/ JACKSON E. REASOR

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

Exhibit 31.2

CERTIFICATIONS

I, Robert L. Kees, certify that:

1. I have reviewed this 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. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

(a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 9, 2016

/s/ ROBERT L. KEES

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

Exhibit 32.1

OLD DOMINION ELECTRIC COOPERATIVE

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

In connection with the Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 9, 2016

/s/ JACKSON E. REASOR

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

Exhibit 32.2

OLD DOMINION ELECTRIC COOPERATIVE

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

In connection with the Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 9, 2016

/s/ ROBERT L. KEES

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