part 2

160440071

Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

PUBLIC VERSION

Case No. PUE-2016-00049
Docket No. E-100, Sub 147

Filed: April 29, 2016

TABLE OF CONTENTS

LIST OF ACRONYMS

Acronym	Meaning
2015 Plan	2015 Integrated Resource Plan
2016 Plan	2016 Integrated Resource Plan
AC	Alternating Current
ACP	Atlantic Coast Pipeline
AMI	Advanced Metering Infrastructure
BTMG	Behind-the-Meter Generation
Btu	British Thermal Unit
CAPP	Central Appalachian
CC	Combined-Cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CEIP	Clean Energy Incentive Program
CFB	Circulating Fluidized Bed
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction Permit and Operating License
Company	Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan, Rule 111(d)
CSAPR	Cross-State Air Pollution Rule
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
DC	Direct Current
DEQ	Virginia Department of Environmental Quality
DG	Distributed Generation
DOE	U.S. Department of Energy
DOM LSE	Dominion Load Serving Entity
DOM Zone	Dominion Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization
DSM	Demand-Side Management
EGU	Electric Generating Units
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ERC	Emission Rate Credit
ESBWR	Economic Simplified Boiling Water Reactor
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GEH	GE-Hitachi Nuclear Energy Americas LLC
GHG	Greenhouse Gas
GSP	Gross State Product
GWh	Gigawatt Hour(s)
Hg	Mercury
HVAC	Heating, Ventilating, and Air Conditioning
ICF	ICF International, Inc.
IDR	Interval Data Recorder
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated-Gasification Combined-Cycle
IRM	Installed Reserve Margin
IRP	Integrated Resource Planning
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt Hour(s)
LMP	Locational Marginal Pricing
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
LTC	Load Tap Changer

Acronym	Meaning
MATS	Mercury and Air Toxics Standards
MMBTU	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt(s)
MWh	Megawatt Hour(s)
MVA	Mega Volt Ampere
NAAQS	National Ambient Air Quality Standards
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	The National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NUG	Non-Utility Generation or Non-Utility Generator
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturers
PC	Pulverized Coal
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection, L.L.C.
Plan	2016 Integrated Resource Plan
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
RAC	Rate Adjustment Clause
RACT	Reasonable Available Control Technology
REC	Renewable Energy Certificate
REPS	Renewable Energy and Energy Efficiency Portfolio Standard (NC)
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RPM	Reliability Pricing Model
RPS	Renewable Energy Portfolio Standard (VA)
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	Virginia State Corporation Commission
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction
SG	Standby Generation
SIP	State Implementation Plan
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SPP	Solar Partnership Program
SRP	Stakeholder Review Process
STAP	Short-Term Action Plan
Strategist	Strategist Model
T&D	Transmission and Distribution
TOU	Time-of-Use Rate
TRC	Total Resource Cost
UCT	Utility Cost Test
Va. Code	Code of Virginia
VCHEC	Virginia City Hybrid Energy Center
VOW	Virginia Offshore Wind Coalition
VOWDA	Virginia Offshore Wind Development Authority
VOWTAP	Virginia Offshore Wind Technology Advancement Project
WACC	Weighted Average Cost of Capital
WEA	Wind Energy Area
WTI	West Texas Intermediate

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTEGRATED RESOURCE PLAN OVERVIEW

Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power (collectively, the "Company") hereby files its 2016 Integrated Resource Plan ("2016 Plan" or "Plan") with the Virginia State Corporation Commission ("SCC") in accordance with § 56-599 of the Code of Virginia (or "Va. Code"), as amended by Senate Bill 1349 ("SB 1349") effective July 1, 2015 (Chapter 6 of the 2015 Virginia Acts of Assembly), and the SCC's guidelines issued on December 23, 2008. The Plan is also filed with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of NCUC's Rules and Regulations.

The 2016 Plan was prepared for the Dominion Load Serving Entity ("DOM LSE"), and represents the Company's service territories in the Commonwealth of Virginia and the State of North Carolina, which are part of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization ("RTO"). Subject to provisions of Virginia and North Carolina law, the Company prepares an integrated resource plan for filing in each jurisdiction every year. Last year, the Company filed its 2015 Integrated Resource Plan ("2015 Plan") with the SCC (Case No. PUE-2015-00035) and as an update with the NCUC (Docket No. E-100, Sub 141). On December 30, 2015, the SCC issued its Final Order finding the 2015 Plan ("2015 Plan Final Order") in the public interest and reasonable for filing as a planning document, and requiring additional analyses in several areas be included in future integrated resource plan filings. On March 22, 2016, the NCUC issued an order accepting the Company's update filing as complete and fulfilling the requirements set out in NCUC Rule R8-60.

As with each Plan filing, the Company is committed in this 2016 Plan to addressing concerns and/or requirements identified by the SCC or NCUC in prior relevant orders, as well as new or proposed provisions of state and federal law. Notably, for purposes herein, this document includes the greenhouse gas ("GHG") regulations promulgated by the U.S. Environmental Protection Agency ("EPA") on August 3, 2015. These final EPA GHG regulations, known as the Clean Power Plan ("CPP") or 111(d) Rule, provide states with several options for restricting carbon dioxide ("CO_2") emissions, either through tonnage caps on the total amount of carbon generated by electric generating units ("EGUs"), or through rate-based restrictions on the average amount of CO_2 emitted per unit of electricity generated for all EGUs or for specific classes of EGUs, which is an approach generally referred to as carbon intensity regulation.

The CPP, and the Company's evaluation of compliance with these emission levels, as they existed before the CPP was stayed by the February 9, 2016 Order ("Stay Order") of the Supreme Court of the United States ("Supreme Court"), is presented herein. The Supreme Court's Stay Order has the effect of suspending the implementation and enforcement of the CPP pending judicial review by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") and possibly the Supreme Court. However, as discussed further below, the Company has elected to continue to evaluate CPP compliance. Even with the exact future of the CPP undetermined at present, the Company believes that future regulation will require it to address carbon and carbon emissions in some form beyond what is required today. Therefore, it is critical at this time that the Company preserves all options available that will ensure the Company, its customers, and the Commonwealth of Virginia can efficiently transition to a low carbon future while maintaining reliability. This includes the continued reasonable development efforts associated with traditional and new low- or zero-emitting supply side resources such as new nuclear (North Anna 3), onshore wind, offshore wind, and solar along with cost-effective demand-side resources. Many of these resources are included in the alternative plans examined in this 2016 Plan. Some of these resources, however, have not been included given the time period examined and other constraints incorporated into this 2016 Plan. This is not to say that these resources will not be needed in the future. In fact the Company maintains that it is highly likely that resources such as North Anna 3, wind generation, and new demand-side resources will be needed at some point in the future beyond that studied in this 2016 Plan, or sooner should fuel prices increase (especially natural gas prices). Throughout this document, the Company has made it a point to identify areas of future uncertainty including uncertainty associated with future carbon emissions regulation. One must ask, will the CPP remain in its current form or will it be revised? Also, should the CPP remain intact as promulgated, what happens beyond the 2030 final target date? When considering questions such as these, it is reasonable to anticipate that resources such as North Anna 3, offshore wind, and new demand-side resources may be required in the future in order to provide reliable electric service to the Company's customers. A reasonable albeit simplified conclusion is "not if but when" will these resources be needed. As mentioned above, in this 2016 Plan some of these resources are not included but those same resources may be reasonable choices in future Plans. Continuing the significant progress is particularly important with extremely long lead time generation projects like North Anna 3 and off-shore wind. Therefore, once again, it is imperative that the Company preserve its supply- and demand-side options for the future.

Additionally, low natural gas prices along with societal pressures and/or regulatory constraints have adversely impacted the U.S. coal generation fleet which has resulted in an extraordinarily high level of coal unit retirements over the last five to ten years. Certainly several of the Company's own coal-fired units have not escaped this fate. With these pressures in mind it is important to understand that the Company's coal generation fleet has been the backbone of its generation portfolio and have reliably served the Company's customers for many years. Simultaneously, these facilities have also added a key element of diversity to the Company's overall fleet which has helped keep rates stable in the Commonwealth of Virginia and North Carolina. As Virginia and the nation transitions to a low carbon future this element of diversity must not be lost. The Company's goal is to find ways to efficiently add to its generation fleet diversity while maintaining its coal fleet. The Company asserts that this strategy will, in the long term, provide superior benefit to our customers similar to the value such diversity has provided those same customers in the past.

Incorporated in this 2016 Plan are provisions of SB 1349, which amend Va. Code § 56-599, including requiring annual integrated resource plans from investor-owned utilities by May 1 of each year starting in 2016, and establishing a "Transitional Rate Period" consisting of five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. During the Transitional Rate Period, SB 1349 directs the SCC to submit a report and make recommendations to the Governor and the Virginia General Assembly by December 1 of each year, which assesses the updated integrated resource plan of any investor-owned incumbent electric utility, including an analysis of the amount, reliability and type of generation facilities needed to serve Virginia native load compared to what is then available to serve such load and what may be available in the future in view of market conditions and current and pending state and federal environmental regulations. The reports must also estimate impacts in Virginia on electric rates based on implementation of the CPP. This is the Company's second integrated resource plan submitted during the Transitional Rate Period. The information and analysis presented herein are intended to inform the reporting requirements for the SCC, as well as reflect the period of uncertainty continuing to face the Company during the Transitional Rate Period, as recognized by the Governor and the Virginia General Assembly through passage of SB 1349.

As with prior filings, the Company's objective was to identify the mix of resources necessary to meet its customers' projected energy and capacity needs in an efficient and reliable manner at the lowest reasonable cost, while considering future uncertainties. The Company's options for meeting these future needs are: i) supply-side resources, ii) demand-side resources, and iii) market purchases. A balanced approach, which includes consideration of options for maintaining and enhancing rate stability, energy independence and economic development, as well as input from stakeholders, will help the Company meet growing demand, while protecting customers from a variety of potentially negative impacts and challenges. These include changing regulatory requirements, particularly the EPA's regulation of CO_2 emissions from new and existing electric generation, as well as commodity price volatility and reliability concerns based on overreliance on any single fuel source.

The Company primarily used the Strategist model ("Strategist"), a utility modeling and resource optimization tool, to develop this 2016 Plan over a 25-year period, beginning in 2017 and continuing through 2041 ("Study Period"), using 2016 as the base year. Unless otherwise specified, text, numbers, and appendices are displayed for a 15-year period from 2017 to 2031 ("Planning Period") for Plan B: Intensity-Based Dual Rate. This 2016 Plan is based on the Company's current assumptions regarding load growth, commodity price projections, economic conditions, environmental regulations, construction and equipment costs, Demand-Side Management ("DSM") programs, and many other regulatory and market developments that may occur during the Study Period.

Included in this 2016 Plan are sections on load forecasting and alternative rate studies (Chapter 2), existing resources and resources currently under development (Chapter 3), planning assumptions (Chapter 4), and future resources (Chapter 5). Additionally, there is a section describing the development of the Plan (Chapter 6), which defines the integrated resource planning ("IRP") process, and outlines alternative plans that were compared by weighing the costs of those plans using a variety of scenarios and other non-cost factors, and also further compared by using a comprehensive risk analysis; and a Portfolio Evaluation Scorecard (or "Scorecard") process. This analysis allowed the Company to examine alternative plans given significant industry uncertainties, such as environmental regulations, commodity and construction prices, and resource mix. The Scorecard provides a quantitative and qualitative measurement system to assess the different alternatives, using criteria that include cost, rate stability, and benefits and risks. Finally, a Short-Term Action Plan (or "STAP") (Chapter 7) is included, which discusses the Company's specific actions currently underway to support the 2016 Plan over the next five years (2017 - 2021). The STAP represents the short-term path forward that the Company maintains will best meet the energy and capacity needs of its customers at the lowest reasonable cost over the next five years, with due quantification, consideration and analysis of future risks and uncertainties facing the industry, the Company, and its customers.

As noted above, the Company's balanced approach to developing its Plan also includes input from stakeholders. Starting in 2010, the Company initiated its Stakeholder Review Process ("SRP") in Virginia, which is a forum to inform stakeholders from across its service territory about the IRP process, and to provide more specific information about the Company's planning process, including IRP and DSM initiatives, and to receive stakeholder input. The Company coordinates with interested parties in sharing DSM program Evaluation, Measurement and Verification ("EM&V") results and in developing future DSM program proposals, pursuant to an SCC directive. The Company is committed to continuing the SRP and expects the next SRP meeting involving stakeholders across its service territory to be after the filing of this 2016 Plan.

Finally, the Company notes that inclusion of a project or resource in any given year's integrated resource plan is not a commitment to construct or implement a particular project or a request for approval of a particular project. Conversely, not including a specific project in a given year's plan does not preclude the Company from including that project in subsequent regulatory filings. Rather, an integrated resource plan is a long-term planning document based on current market information and projections and should be viewed in that context.

1.2 COMPANY DESCRIPTION

The Company, headquartered in Richmond, Virginia, currently serves approximately 2.5 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company's supply-side portfolio consists of 21,107 megawatts ("MW") of generation capacity, including approximately 1,277 MW of fossil-burning and renewable non-utility generation ("NUG") resources, over 6,500 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and more than 57,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia, North Carolina and West Virginia. The Company is a member of PJM, the operator of the wholesale electric grid in the Mid-Atlantic region of the United States.

The Company has a diverse mix of generating resources consisting of Company-owned nuclear, fossil, hydro, pumped storage, biomass and solar facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market.

1.3 2016 INTEGRATED RESOURCE PLANNING PROCESS

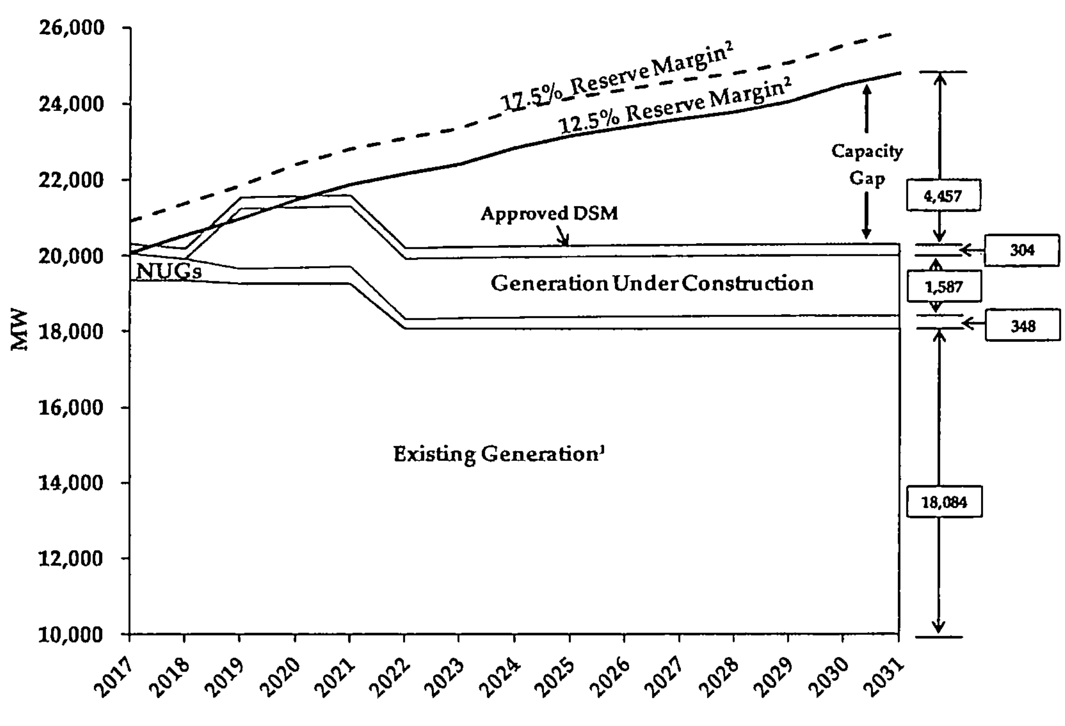
In order to meet future customer needs at the lowest reasonable cost while maintaining reliability and flexibility, the Company must take into consideration the uncertainties and risks associated with the energy industry. Uncertainties assessed in this 2016 Plan include:

- load growth in the Company's service territory;
- effective and anticipated EPA regulations concerning air, water, and solid waste constituents (as shown in Figure 3.1.3.3), particularly including the EPA GHG regulations (i.e., the CPP) regarding CO_2 emissions from electric generating units;
- fuel prices;

- cost and performance of energy technologies;
- renewable energy requirements including integration of intermittent renewable generation;
- current and future DSM;
- retirement of non-Company controlled units that may impact available purchased power volumes; and
- retirement of Company-owned generation units.

The Company developed this integrated resource plan based on its evaluation of various supply- and demand-side alternatives and in consideration of acceptable levels of risk that maintain the option to develop a diverse mix of resources for the benefit of its customers. Various planning groups throughout the Company provided input and insight into evaluating all viable options, including existing generation, DSM programs, and new (both traditional and alternative) resources to meet the growing demand in the Company's service territory. The IRP process began with the development of the Company's long-term load forecast, which indicates that over the Planning Period (2017 – 2031), the DOM LSE is expected to have annual increases in future peak and energy requirements of 1.5% and 1.5%, respectively. Collectively, these elements assisted in determining updated capacity and energy requirements as illustrated in Figure 1.3.1 and Figure 1.3.2.

Figure 1.3.1 - Current Company Capacity Position (2017 – 2031)

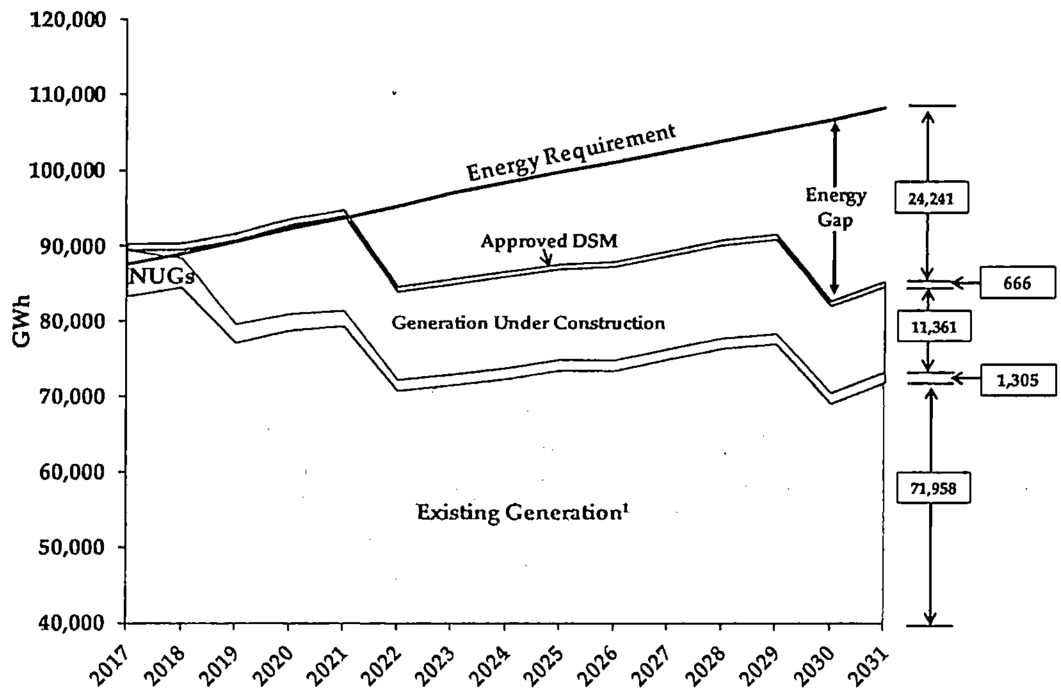


Note: The values in the boxes represent total capacity in 2031.

1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

2) See Section 4.2.2.

Figure 1.3.2 - Current Company Energy Position (2017 – 2031)



Note: The values in the boxes represent total energy in 2031.

1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

1.3.1 EPA's CLEAN POWER PLAN

The importance of lower carbon emitting generation was reinforced on August 3, 2015, with the EPA's issuance of its final EPA GHG regulations. These regulations, known as the Clean Power Plan (also referred to as CPP or 111(d) Rule), would significantly reduce carbon emissions from electric generating units by mandating reductions in carbon emissions. The EPA's CPP offers each state two sets of options to achieve compliance, and a federal implementation plan ("FIP" or "Federal Plan") associated with each set. These options include Rate-Based programs designed to reduce the overall CO_2 intensity (i.e., the rate of CO_2 emissions as determined by dividing the pounds of CO_2 emitted by each megawatt-hour ("MWh") of electricity produced), which are referred to hereinafter as Intensity-Based programs, and Mass-Based programs designed to reduce total CO_2 emission based on tonnage.[1] Under the CPP, each state is required to submit a state implementation plan ("SIP" or "State Plan") to the EPA detailing how it will meet its individual state targets no later than September 6, 2018. It is the Company's understanding that the Commonwealth of Virginia had intended to finalize its State Plan in the fall of 2017, a year sooner than the final submission deadline. As of this writing, both North Carolina and West Virginia have halted all state CPP compliance work pending the resolution of the Supreme Court stay. Further, both North Carolina and West Virginia are challenging the CPP in court.

[1] Although the CPP's enforceability and legal effectiveness have been stayed by the Supreme Court, for purposes of this 2016 Plan, the Company will discuss the provisions of the CPP as if the rules are enforceable and in effect both from a substantive and implementation timeframe standpoint.

Based on the Company's review of the CPP, for each of the two options (i.e., Intensity-Based and Mass-Based) for compliance, there are three sub-options, for making a total of six possible options for state compliance. They are as follows:

Intensity-Based Programs

1) Intensity-Based Dual Rate Program – An Intensity-Based CO_2 program that requires each existing: (a) fossil fuel-fired electric steam generating unit to achieve an intensity target of 1,305 lbs of CO_2 per MWh by 2030 and beyond; and (b) natural gas combined-cycle ("NGCC") unit to achieve an intensity target of 771 lbs of CO_2 per MWh by 2030, and beyond. These standards, which are based on national CO_2 performance rates, are consistent for any state that opts for this program.
2) Intensity-Based State Average Program – An Intensity-Based CO_2 program that requires all existing fossil fuel-fired generation units in the state to collectively achieve a portfolio average intensity target by 2030, and beyond. In Virginia, that average intensity is 934 lbs of CO_2 per MWh by 2030, and beyond. The 2030 and beyond targets for West Virginia and North Carolina are 1,305 lbs of CO_2 per MWh and 1,136 lbs of CO_2 per MWh, respectively.
3) A Unique State Intensity-Based Program - A unique state Intensity-Based program designed so that the ultimate state level intensity target does not exceed those targets described in the two Intensity-Based programs set forth above.

Mass-Based Programs

4) Mass-Based Emissions Cap (existing units only) Program – A Mass-Based program that limits the total CO_2 emissions from a state's existing fleet of fossil fuel-fired generating units. In Virginia, this limit is 27,433,111 short tons CO_2 in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,325,342 short tons of CO_2 and 51,266,234 short tons of CO_2, respectively.
5) Mass-Based Emissions Cap (existing and new units) Program – A Mass-Based program that limits the total CO_2 emissions from both the existing fleet of fossil-fuel fired generating units and all new generation units in the future. In Virginia, this limit is 27,830,174 short tons of CO_2 by 2030. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,857,307 short tons of CO_2 and 51,876,856 short tons of CO_2, respectively.
6) Unique State Mass-Based Program - A unique state Mass-Based approach limiting total CO_2 emissions.

The Company anticipates that the Unique State Intensity-Based and Mass-Based Programs identified above (sub-options 3 and 6) are unlikely choices for the states in which the Company's generation fleet is located in part because of the time constraints for states to implement programs, and because of the restrictions that a unique state program would impose on operating flexibility and compliance coordination among states. Therefore, the 2016 Plan assesses the remaining four programs that are likely to be implemented in Virginia, West Virginia, and North Carolina. Per the CPP, compliance for each of the four programs begins in 2022, and includes interim CO_2 targets that must be achieved prior to the final targets in 2030 and beyond specified above. Figures 1.3.1.1 through 1.3.1.3 identify these interim targets per program per state. Also, each of the four programs has different compliance requirements that will be described in more detail in Chapters 3 and 6.

Figure 1.3.1.1 – CPP Implementation Options – Virginia

	Intensity-Based Program Existing Units (lbs/Net MWh)			Mass-Based Program (short tons)	
	Dual Rate (EGU specific)		State Average	Emissions Cap	Emissions Cap
	Steam	NGCC		Existing Units Only	Existing and New Units
2012 Baseline			1,477	27,365,439	
Interim Step 1 Period 2022 - 2024	1,671	877	1,120	31,290,209	31,474,885
Interim Step 2 Period 2025 - 2027	1,500	817	1,026	28,990,999	29,614,008
Interim Step 3 Period 2028 - 2029	1,380	784	966	27,898,475	28,487,101
Final Goal 2030 and Beyond	1,305	771	934	27,433,111	27,830,174

Figure 1.3.1.2 – CPP Implementation Options – West Virginia

	Intensity-Based Program Existing Units (lbs/Net MWh)			Mass-Based Program (short tons)	
	Dual Rate (EGU specific)		State Average	Emissions Cap	Emissions Cap
	Steam	NGCC		Existing Units Only	Existing and New Units
2012 Baseline			2,064	72,318,917	
Interim Step 1 Period 2022 - 2024	1,671	877	1,671	62,557,024	62,804,443
Interim Step 2 Period 2025 - 2027	1,500	817	1,500	56,762,771	57,597,448
Interim Step 3 Period 2028 - 2029	1,380	784	1,380	53,352,666	54,141,279
Final Goal 2030 and Beyond	1,305	771	1,305	51,325,342	51,857,307

Figure 1.3.1.3 – CPP Implementation Options – North Carolina

	Intensity-Based Program Existing Units (lbs/Net MWh)			Mass-Based Program (short tons)	
	Dual Rate (EGU specific)		State Average	Emissions Cap	Emissions Cap
	Steam	NGCC		Existing Units Only	Existing and New Units
2012 Baseline			1,790	58,566,353	
Interim Step 1 Period 2022 - 2024	1,671	877	1,419	60,975,831	61,259,834
Interim Step 2 Period 2025 - 2027	1,500	817	1,283	55,749,239	56,707,332
Interim Step 3 Period 2028 - 2029	1,380	784	1,191	52,856,495	53,761,714
Final Goal 2030 and Beyond	1,305	771	1,136	51,266,234	51,876,856

As mentioned above, on February 9, 2016, the Supreme Court voted 5-4 to issue an order staying implementation of the CPP pending judicial review of the rule by the D.C. Circuit Court of Appeals and any subsequent review by the Supreme Court (i.e., the Stay Order). Oral arguments are scheduled before the D.C. Circuit Court on June 2, 2016. The Company believes the earliest the appeal process will be resolved is the fall of 2017.

At this time, the EPA has not indicated whether and, if so, to what extent the stay will affect the CPP compliance timeline. While it is anticipated that the deadline for states to submit their SIPs to the EPA will be delayed proportionately to the duration of the stay (i.e., around 2 years), it is uncertain whether the initial (2022) or final (2030) compliance dates will likewise be delayed. Subsequent to the issuance of the Stay Order, Virginia announced that it will continue development of a SIP. North Carolina and West Virginia have suspended development of SIPs at this time.

Due to this delay in the procedural status of the CPP, uncertainty has increased significantly both from a substantive and timing perspective. As acknowledged by the SCC, "significant uncertainty regarding the Clean Power Plan compliance existed at the time the Company filed its [2015] IRP and will likely continue for some time," including uncertainty as to the type of compliance program the states would ultimately select among the many pathways for compliance (i.e., one of the six identified programs under Intensity-Based or Mass-Based approaches). (2015 Plan Final Order at 5.) The ongoing litigation that is the subject of the Stay Order now creates additional uncertainty associated with the CPP's ultimate existence and the timing for compliance. As a result, the need for effective, comprehensive, long-range planning is even more important so that the Company can be prepared on behalf of its customers for the multitude of scenarios that the future may bring.

Reflecting this uncertainty and the need to plan for a variety of contingencies, the Company presents in this 2016 Plan five different alternative plans (collectively, the "Studied Plans") designed to meet the needs of its customers in a future both with or without a CPP. To assess a future without a CPP, the 2016 Plan includes an alternative designed using least-cost planning techniques and assuming no additional carbon regulation is implemented pursuant to the CPP (hereinafter identified as "Plan A: No CO_2 Limit" or "No CO_2 Plan"). Four additional alternative plans are designed to be compliant with the CPP as set forth in the final rule ("CPP-Compliant Alternative Plans" or "Alternative Plans") utilizing one of the four program options likely to be implemented in the Commonwealth of Virginia, where the bulk of the Company's generation assets are located (i.e., Intensity-Based Dual Rate, Intensity-Based State Average, Mass-Based Emissions Cap (existing units only) and Mass-Based Emissions Cap (existing and new units) programs). However, it should be noted that the Company considers it likely that there will be future regulation requiring it to address carbon and carbon emissions in some form beyond what is required today, even with the exact future of the CPP, at present, undetermined.

1.3.2 SCC's 2015 PLAN FINAL ORDER

As mentioned above, the SCC's Final Order found, in part, the 2015 Plan to be in the public interest and reasonable for filing as a planning document. Due to future regulatory and market uncertainties at the time of the filing of the 2015 Plan, including significant uncertainty surrounding the draft status of the CPP and the lack of knowledge of the requirements of the final CPP, ultimately released several months after the 2015 Plan was filed, the Company did not include a "Preferred Plan" or recommended path forward beyond the STAP. Instead, the 2015 Plan presented a set of alternative plans that represented potential future paths in an effort to test different resources strategies against plausible scenarios that might occur. Although opposition was raised to this approach, the 2015 Plan Final Order found that the Code of Virginia does not require the SCC to reject integrated resource plan filings that do not identify a stated preferred plan. (2015 Plan Final Order at 4.) Indeed, the SCC concluded, "The lack of a preferred plan is reasonable in this case given the substantial regulatory and planning uncertainty regarding the Clean Power Plan...." (2015 Plan Final Order at 6.)

In addition to its public interest and reasonableness findings, the 2015 Plan Final Order required that additional analyses in several areas be included in future integrated resource plan filings. The Company has complied with each bulleted requirement in the 2015 Plan Final Order, including the SCC's directive that the Company include with its filing an index that identifies the specific location(s) within the 2016 Plan that complies with each bulleted requirement ("Index"), which is attached to the filing letter included with this 2016 Plan filing. (2015 Plan Final Order at 18.) The Company is contemporaneously filing with the 2016 Plan a legal memorandum, which addresses legal issues raised in the 2015 Plan Final Order, as identified in the Index.

1.4 2016 PLAN

Prior to the Supreme Court stay, the Company believed it had more certainty as to a "Preferred Plan" or a recommended path forward in the 2016 Plan beyond the STAP based on the promulgation of the final CPP in August 2015. However, the Supreme Court's February 2016 stay of the procedural status of the CPP has created a regulatory environment that may be even more uncertain than existed prior to filing the 2015 Plan, which was based on a proposed rule that was significantly different from the final CPP.

As a result, there is significantly increased uncertainty surrounding the CPP, creating a circumstance in which the Company must legitimately analyze a future without the CPP, as well as one with the CPP implemented as promulgated in August 2015. Due to the recent timing of the Stay Order, the Company had insufficient time to analyze a future with a delayed implementation of the CPP or a future in which the CPP did not exist but carbon regulation took another form, a scenario the Company considers likely in the absence of the CPP. Therefore, at this time and as was the case in the 2015 Plan, the Company is unable to identify a "Preferred Plan" or a recommended path forward beyond the STAP. Rather in compliance with the 2015 Plan Final Order, the Company is presenting the five Studied Plans. The Company believes the Studied Plans represent plausible future paths for meeting the future electric needs of its customers while responding to changing regulatory requirements.

The first Studied Plan is designed using least-cost planning techniques and no additional carbon regulation:

- Plan A: No CO_2 Limit: This Studied Plan includes 400 MW of Virginia utility-scale solar generation to be phased in from 2016 - 2020, and also includes approximately 600 MW of North Carolina solar NUG generation that is expected to be online by the end of 2017. Plan A also reduces retirements of steam units, which continue to add fuel diversity to the Company's generation fleet and thereby help mitigate rate volatility to the Company's customers. Although Plan A: No CO_2 Limit is designed assuming a future without the CPP, the inclusion of the solar generation mentioned above positions the Company and its customers to either: (i) comply with the CPP in the event that the rule is ultimately upheld; or (ii) minimize compliance costs should the CPP be struck down. Should there be a future without the CPP or other additional carbon regulations, the Company would follow Plan A: No CO_2 Limit. However, as noted above, the Company believes it is likely that it will be subject to some form of carbon regulation in the future, even if the CPP is ultimately overturned by the federal courts. Also, as noted above, the Company lacked sufficient time to analyze during the development of this report the possible impact of alternative forms of carbon regulation on its long-range planning process.

In the event that the CPP is upheld as promulgated in August 2015, the 2016 Plan also includes the CPP-Compliant Alternative Plans that comply with the four likely programs that may be adopted by the Commonwealth of Virginia. These Alternative Plans in ascending order of compliance difficulty are:

- Plan B: Intensity-Based Dual Rate;
- Plan C: Intensity-Based State Average;
- Plan D: Mass-Based Emissions Cap (existing units only); and
- Plan E: Mass-Based Emissions Cap (existing and new units).

Plans B through E were designed using least cost analytical methods given the constraints of the CPP state compliance program options. Further, each of these Alternative Plans were designed in accordance with the final CPP with the intent that the Company would achieve CPP compliance independently, with no need to rely on purchasing CO_2 allowances or emission rate credits ("ERCs"). While the system was modeled as an "island," the Company expects markets for CPP ERCs and CO_2 allowances to evolve and favors CPP programs that encourage trading of ERCs and/or CO_2 allowances. Trading provides a clear market price signal which is the most efficient means of emission mitigation. Also, trading offers flexibility in the event of years with unit outages or non-normal weather. As the CPP trading markets materialize once the EPA model trading rules are finalized and as SIPs are developed, the Company will incorporate ERC and CO_2 allowance trading assumptions into its analysis. However, the Company maintains its island approach to trading is prudent for modeling purposes at this time in light of the uncertainty surrounding future markets for ERCs and CO_2 allowances that are not currently in place.

Based on this analysis, should the CPP be upheld in its current form, the Company believes that the adoption of a CPP compliance program option that is consistent with an Intensity-Based Dual Rate Program, as identified by the EPA, offers the most cost-effective and flexible option for achieving compliance with the CPP in the Commonwealth of Virginia. Indeed, as supported by the analysis conducted in this 2016 Plan, if the CPP is implemented in its current form, an Intensity-Based Dual Rate Program will be the least costly to the Company's customers and offer the Commonwealth the most flexibility over time in meeting environmental regulations and addressing economic development concerns. As further explained in Chapter 3, the flexibility associated with an Intensity-Based Dual Rate Program directly corresponds to the quantity of renewable resources, energy efficiency, and/or new nuclear generation available in Virginia through Company-built resources or programs, or resources purchased within or outside the Commonwealth. The availability of these resources needs to be contrasted against a Mass-Based program which, by definition, dictates adherence to hard caps on CO_2 emissions that limit the compliance options available to the Commonwealth, which in all likelihood, will further increase cost and rate volatility for customers. It is the Company's position that an Intensity-Based Dual Rate Program will provide the Commonwealth with the most CPP compliance flexibility, which, in turn, will help mitigate compliance costs over time.

Furthermore, the Company believes that a Mass-Based program that includes all units (existing and new), as modeled in Plan E: Mass-Based Emissions Cap (existing and new units) will be difficult to achieve by any state similar in EGU make-up to the Commonwealth of Virginia that anticipates economic growth. As shown in Chapter 6, compliance under Plan E: Mass-Based Emissions Cap (existing and new units) is not only the highest cost alternative of the Studied Plans, it also models the potential retirement of the Company's entire Virginia coal generation fleet, including VCHEC, which would result in additional economic hardship to the Virginia communities where these facilities are located.

As in the 2015 Plan, the Company will continue to analyze operational issues created by coal unit retirements. In addition to providing fuel diversity to the Company's existing portfolio, coal has significant operational benefits, notably the proven ability to operate as a baseload resource and capability of storing substantial fuel on site. During its 2015 Session, the Virginia General Assembly enacted SB 1349 with the goal, in part, of maintaining coal as a significant part of the Company's generation portfolio as long as possible, recognizing the regulatory threat to existing coal units posed by the CPP.

Going forward, the Company will continue to analyze both the operational implications and challenges of the Alternative Plans set forth in this document, as well as options for keeping existing generation, including coal units, operational when doing so is in the best interest of customers and the Commonwealth and also in compliance with federal and state laws and regulations. For the benefits of its customers and for Virginia's economy, the Company will also continue to work to maintain its long-standing service tradition of providing competitive rates, a diverse mix of generation, and reliable service. The Company continues to believe that these three factors are closely interrelated.

To evaluate external market and environmental factors that are subject to uncertainty and risk, the Company evaluated the Studied Plans using 3 scenarios and 12 rate design sensitivities, as discussed in Chapters 2 and 6. Further, the Company conducted a comprehensive risk analysis on the Studied Plans in an effort to help quantify the risks associated with each. The results of the analysis are presented in a Portfolio Evaluation Scorecard with respect to each of the Studied Plans.

There are several elements common to all of the Studied Plans. For example, all include VOWTAP, 12 MW (nameplate), as early as 2018, and 400 MW (nameplate) of Virginia utility-scale solar generation to be phased in from 2016 - 2020. These Plans also include 600 MW of North Carolina solar generation from NUGs under long-term contracts to the Company, as well as 7 MW (8 MW Direct Current ("DC")) from the Company's Solar Partnership Program ("SPP") by 2017. The SPP initiative installs Company-owned solar arrays on rooftops and other spaces rented from customers at sites throughout the service area. The Studied Plans also assume that all of the Company's existing nuclear generation will receive 20-year license extensions that lengthen their useful lives beyond the Study Period. The license extensions for Surry Units 1 and 2 are included in 2033 and 2034, respectively, as well as the license extensions for North Anna Units 1 and 2 in 2038 and 2040, respectively.

The electric power industry has been, and continues to be, dynamic in nature, with rapidly changing developments, market conditions, technology, public policy, and regulatory challenges. Certainly, the current stay of CPP implementation exemplifies such rapidly developing challenges, and the Company expects that these dynamics will continue in the future and will be further complicated by larger-scale governmental or societal trends, including national security considerations (which include infrastructure security), environmental regulations, and customer preferences. Therefore, it is prudent for the Company to preserve a variety of reasonable development options in order to respond to the future market, regulatory, and industry uncertainties which are likely to occur in some form, but difficult to predict at the present time.

Consequently, the Company recommends (and plans for), at a minimum, continued monitoring along with reasonable development efforts of the additional demand- and supply-side resources included in the Studied Plans as identified in Chapter 6. The Studied Plans are summarized in Figure 1.4.1.

Figure 1.4.1 - 2016 Studied Plans

Year		Compliant with Clean Power Plan				Renewables, Retirements, Extensions and DSM included in all Plans			
	Plan A: No CO_2 Limit	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)	Renewable	Retrofit	Retire	DSM[1]
2017						SLR NUG (204 MW)[3] SPP (7 MW)[3]		YT 1-2	
2018						VOWTAP	PP5 - SNCR		
2019	Greensville	Greensville	Greensville	Greensville	Greensville				
2020		SLR (200 MW)	SLR (400 MW)	SLR (200 MW)	SLR (800 MW)	VA SLR (400 MW)[6]			
2021		SLR(200MW)	SLR (400 MW)	SLR (200 MW)	CT SLR (800 MW)				
2022	CT	3x1 CC SLR (200 MW)	3x1 CC SLR (400 MW)	3x1 CC SLR (200 MW)	2x1 CC CT SLR (800 MW)			YT 3[4], CH 3-4[4], CH 5-6[4], CL 1-2[4], MB 1-2[4]	Approved & Proposed DSM 330 MW by 2031 752 GWh by 2031
2023	CT	CT SLR (200 MW)	SLR (400 MW)	CT SLR (200 MW)	SLR (800 MW)				
2024		SLR (200 MW)	CT SLR (400 MW)	SLR (200 MW)	CT SLR (800 MW)				
2025		SLR (100 MW)	SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2026			SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2027			SLR (200 MW)	SLR (200 MW)	SLR (800 MW)				
2028	3x1 CC		SLR (200 MW)	SLR (200 MW)	SLR (600 MW)				
2029			SLR (200 MW)	SLR (200 MW)	NA3[2]			VCHEC[5]	
2030		3x1 CC	SLR (200 MW)	3x1 CC SLR (200 MW)					
2031			SLR (200 MW)	SLR (200 MW)					

Key: Retire: Remove a unit from service; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; NA3: North Anna 3; PP5: Possum Point Unit 5; SNCR: Selective Non-Catalytic Reduction; SLR: Generic Solar; SLR NUG: Solar NUG; SPP: Solar Partnership Program; VA SLR: Generic Solar built in Virginia; VCHEC: Virginia City Hybrid Energy Center; VOWTAP: Virginia Offshore Wind Technology Advancement Project; YT: Yorktown Unit.

Note: Generic SLR shown in the Studied Plans is assumed to be built in Virginia.

1) DSM capacity savings continue to increase throughout the Planning Period.

2) Earliest possible in-service date for North Anna 3 is September 2028, which is reflected as a 2029 capacity resource.

3) SPP and SLR NUG started in 2014. 600 MW of North Carolina Solar NUGs include 204 MW in 2017; 396 MW was installed prior to 2017.

4) The potential retirement of Yorktown Unit 3 and the potential retirements of Chesterfield Units 3-4 and Mecklenburg Units 1-2 are modeled in all of the CPP-Compliant Alternative Plans (B, C, D and E). The potential retirements of Chesterfield Units 5-6 and Clover Units 1-2 are modeled in Plan E. The potential retirements occur in December 2021, with capacity being unavailable starting in 2022.

5) The potential retirement of VCHEC in December 2028 (capacity unavailable starting in 2029) is also modeled in Plan E.

6) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 to 2020.

Common elements of the Studied Plans

The following are common to the Studied Plans through the Planning Period:

- **Demand-Side Resources (currently evaluated):**
    - approved DSM programs reaching approximately 304 MW by 2031;
    - proposed DSM programs reaching approximately 26 MW by 2031;
- **Generation under Construction:**
    - Greensville County Power Station, approximately 1,585 MW of natural gas-fired CC capacity by 2019;
    - Solar Partnership Program, consisting of 7 MW (nameplate) (8 MW DC) of capacity of solar distributed generation (or "DG") by 2017;
- **Generation under Development:**
    - Virginia utility-scale solar generation, approximately 400 MW (nameplate), to be phased in from 2016 - 2020;
        - Including Scott (17 MW), Whitehouse (20 MW) and Woodland (19 MW);
    - Virginia Offshore Wind Technology Advancement Project ("VOWTAP"), approximately 12 MW (nameplate) as early as 2018;
- NUGs:
    - 600 MW (nameplate) of North Carolina solar NUGs by 2017;
- **Retrofit:**
    - Possum Point Power Station Unit 5 "(Possum Point"), retrofitted with Select Non-Catalytic Reduction ("SNCR") by 2018;
- **Retirements:**
    - Yorktown Power Station ("Yorktown") Units 1 and 2 by 2017;
- **Extensions:**
    - Surry Units 1 and 2, license extensions of 20 years by 2033; and
    - North Anna Units 1 and 2, license extensions of 20 years by 2038.

In addition to the supply-side/DSM initiatives listed above that are common to all Studied Plans, the four CPP-Compliant Alternative Plans model the potential retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), Mecklenburg Units 1 (69 MW) and 2 (69 MW) and Yorktown Unit 3 (790 MW) in 2022. Additional resources and retirements are included in the specified Alternative Plans below:

- **Generation Under Development:**
    - Plan E: Mass-Based Emissions Cap (existing and new units) includes 1,452 MW of nuclear generation.

- **Potential Generation:**
    - Plan A: No CO_2 Limit includes one 3x1 CC unit of approximately 1,591 MW and two combustion turbine ("CT")[2] plants of approximately 915 MW;
    - Plan B: Intensity-Based Dual Rate includes two 3x1 CC units of approximately 3,183 MW, one CT plant of 458 MW, as well as 1,100 MW (nameplate) of additional solar;
    - Plan C: Intensity-Based State Average includes one 3x1 CC unit of approximately 1,591 MW, one CT plant of 458 MW, as well as 3,400 MW (nameplate) of additional solar (3,600 MW by 2041);
    - Plan D: Mass-Based Emissions Cap (existing units only) includes two 3x1 CC units of approximately 3,183 MW, one CT plant of 458 MW, as well as 2,400 MW of additional solar (2,600 MW by 2041); and
    - Plan E: Mass-Based Emissions Cap (existing and new units) includes one 2x1 CC unit of approximately 1,062 MW, three CT plants of approximately 1,373 MW and 7,000 MW (nameplate) of additional solar.
- **Retirements:**
    - Plan E: Mass-Based Emissions Cap (new and existing units) includes the potential retirements of Chesterfield Units 5 (336 MW) and 6 (670 MW), and Clover Units 1 (220 MW) and 2 (219 MW) by 2022, as well as the potential retirement of VCHEC (610 MW) by 2029.

Figure 1.4.2 illustrates the renewable resources included in the Studied Plans over the Study Period (2017 - 2041).

Figure 1.4.2 – Renewable Resources in the Studied Plans

Resource	Nameplate MW	Plan A: No CO_2 Limit	Compliant with the Clean Power Plan: Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
Existing Resources	590	x	x	x	x	x
Additional VCHEC Biomass	27	x	x	x	x	x
Solar Partnership Program	7	x	x	x	x	x
Solar NUGs	600	x	x	x	x	x
VA Solar[1]	400	x	x	x	x	x
Solar PV	Varies	-	1,100 MW	3,600 MW	2,600 MW	7,000 MW
VOWTAP	12	x	x	x	x	x

Note: 1) 400 MW of Virginia utility-scale solar generation will be phased in from 2016 - 2020, and includes Scott, Whitehouse and Woodland (56 MW total).

To meet the projected demand of electric customers and annual reserve requirements throughout the Planning Period, the Company has identified additional resources utilizing a balanced mix of supply- and demand-side resources and market purchases to fill the capacity gap shown in Figure 1.3.1. These resources are illustrated in Appendix 1A for all Studied Plans.

[2] All references regarding new CT units throughout this document refer to installation of a bank of two CT units.

The 2016 Plan balances the Company's commitment to operate in an environmentally-responsible manner with its obligation to provide reliable and reasonably-priced electric service. The Company has established a strong track record of environmental protection and stewardship and has spent more than $1.8 billion since 1998 to make environmental improvements to its generation fleet. These improvements have already reduced emissions by 81% for nitrogen oxide ("NO_x"), 96% for mercury ("Hg"), and 95% for sulfur dioxide ("SO_2") from 2000 levels.

Since numerous EPA regulations are effective, anticipated and stayed (as further shown in Figure 3.1.3.3), the Company continuously evaluates various alternatives with respect to its existing units. Coal-fired and/or oil-fired units that have limited environmental controls are considered at risk units. Environmental compliance offers three options for such units: 1) retrofit with additional environmental control reduction equipment, 2) repower (including co-fire), or 3) retire the unit.

With the background explained above, the retrofitted and retired units in the Studied Plans are as follows:

Retrofit

- 786 MW of heavy oil-fired generation installed with new SNCR controls at Possum Point Unit 5 by 2018 (Studied Plans).

Repower

- No units selected for repower at this time.

Retire

- 323 MW of coal-fired generation at Yorktown Units 1 and 2, to be retired by 2017 (Studied Plans);
- 790 MW of oil-fired generation at Yorktown Unit 3, to be potentially retired in 2022 (all CPP-Compliant Alternative Plans);
- 261 MW of coal-fired generation at Chesterfield Units 3 and 4, and 138 MW of coal-fired generation at Mecklenburg Units 1 and 2, all to be potentially retired in 2022 (all CPP-Compliant Alternative Plans);
- 1,006 MW of coal-fired generation at Chesterfield Units 5 and 6, and 439 MW of coal-fired generation at Clover Units 1 and 2, all to be potentially retired in 2022 (Plan E: Mass Emissions Cap (existing and new units)); and
- 610 MW of coal-fired generation at VCHEC, to be potentially retired in 2029 (Plan E: Mass Emissions Cap (existing and new units)).

In this way, the 2016 Plan provides options to address uncertainties associated with potential changes in market conditions and environmental regulations, while meeting future demand effectively through a balanced portfolio.

While the Planning Period is a 15-year outlook, the Company is mindful of the scheduled license expirations of Company-owned nuclear units: Surry Unit 1 (838 MW) and Surry Unit 2 (838 MW) in 2032 and 2033, respectively, and North Anna Unit 1 (838 MW) and North Anna Unit 2 (834 MW) in 2038 and 2040, respectively. At the current time, the Company believes it will be able to obtain license extensions on all four nuclear units at a reasonable cost; therefore, it has included the extensions in all Studied Plans. If the nuclear extensions were not to occur, the Mass-Based Emissions Cap (existing and new units) Program option would be materially impacted. In fact, Plan E: Mass-Based Emissions Cap (existing and new units) would require approximately 8,000 MW (nameplate) of additional solar by 2041. Therefore in total, Plan E: Mass-Based Emissions Cap (existing and new units) without the nuclear extensions would require North Anna 3 and approximately 16,000 MW (nameplate) solar which would not only increase cost significantly, it could potentially cause system operation problems.

While not definitively choosing one plan or a combination of plans beyond the STAP, the Company remains committed to pursuing the development of resources that meet the needs of customers discussed in the Short-Term Action Plan, while supporting the fuel diversity needed to minimize risks associated with changing market conditions, industry regulations, and customer preferences. Until such time as the CPP is upheld or struck down, the Company plans to further study and assess options as if the CPP as promulgated in August 2015 were in place, so that the Company will be prepared to offer a more definitive plan or combination of plans as the future becomes clearer.

1.5 RATE IMPACT OF CPP-COMPLIANT ALTERNATIVE PLANS (2022, 2026, 2030)

Figures 1.5.1 and 1.5.2 reflect the percentage and dollar increase in a typical 1,000 kWh/month residential customer's monthly bill for each CPP-Compliant Alternative Plan, for the years 2022, 2026 and 2030, as compared to Plan A: No CO_2 Limit. A more detailed discussion on the Rate Impact Analysis is provided in Section 6.7. As shown in the figures below, implementation of Mass-Based compliance strategies would have a much greater impact on customer bills than Intensity-Based. For example, the Company estimates that Plan E: Mass-Based Emissions Cap (existing and new units) would raise the typical residential bill on average approximately 22% during the 2022 through 2030 time period, as compared to Plan A: No CO_2 Limit. Whereas, Plan B: Intensity-Based Dual Rate would raise customer bills 3% during the same period.

Figure 1.5.1 – Residential Monthly Bill Increase as Compared to Plan A: No CO_2 Limit (%)

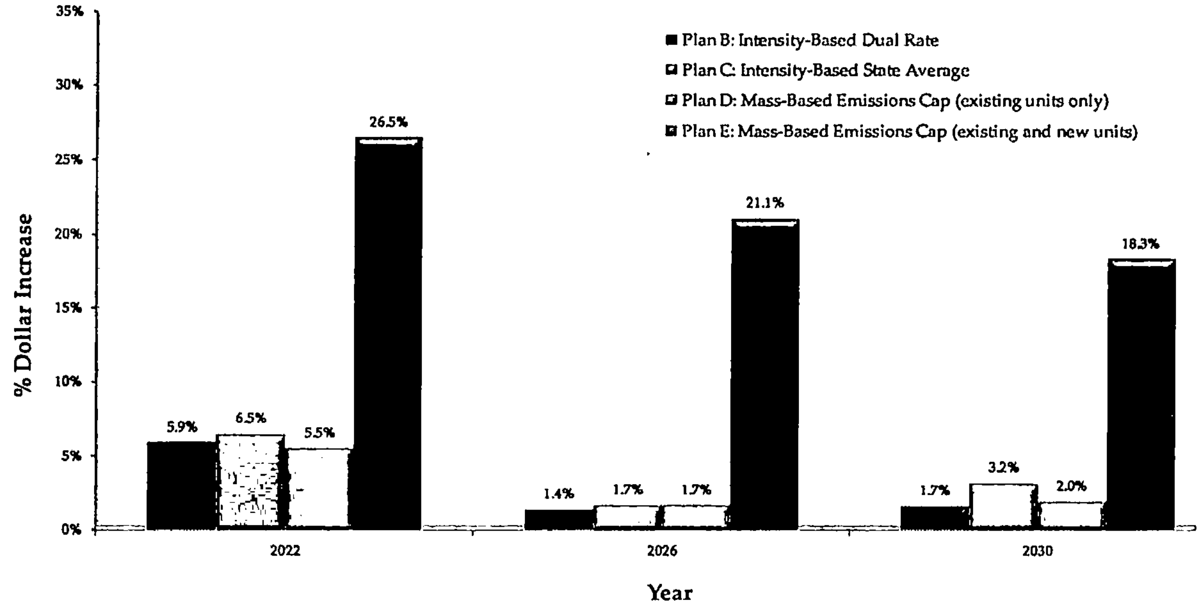
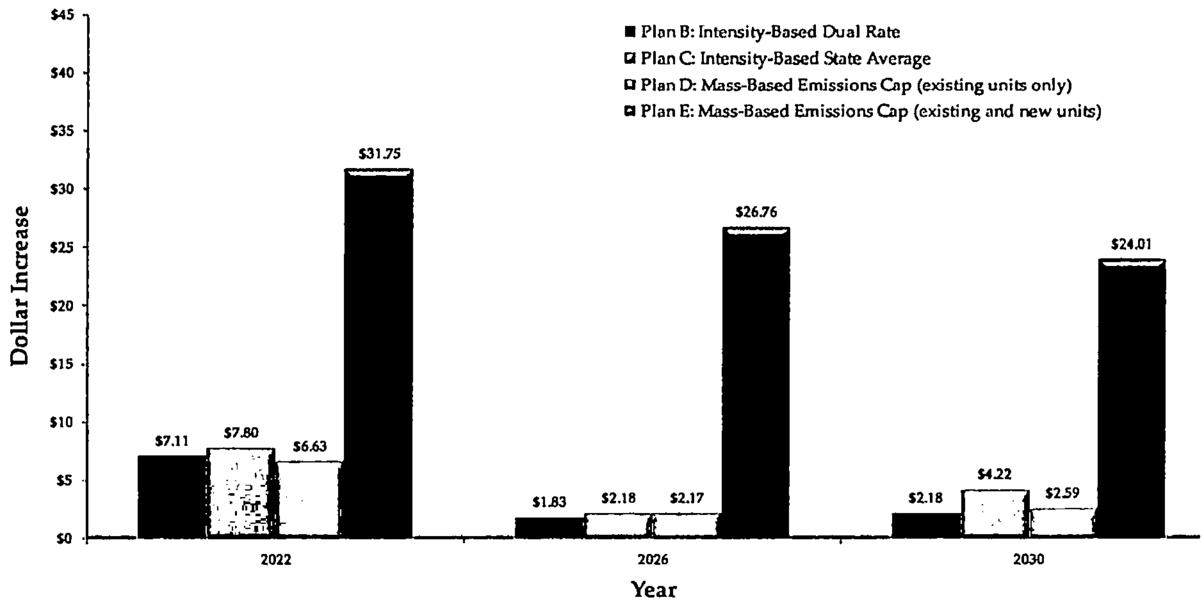


Figure 1.5.2 – Residential Monthly Bill Increase as Compared to Plan A: No CO_2 Limit ($)



CHAPTER 2 – LOAD FORECAST

2.1 FORECAST METHODS

The Company uses two econometric models with an end-use orientation to forecast energy sales. The first is a customer class level model ("sales model") and the second is an hourly load system level model ("system model"). The models used to produce the Company's load forecast have been developed, enhanced, and re-estimated annually for over 20 years, but have remained substantially consistent year-over-year.

The sales model incorporates separate monthly sales equations for residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers, as well as other Load Serving Entities ("LSEs") in the Dominion Zone ("DOM Zone"), all of which are in the PJM RTO. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load.

Variables included in the monthly sales equations are as follows:

- **Residential Sales equation:** Income, electric prices, unemployment rate, number of customers, appliance saturations, building permits, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Commercial Sales equation:** Virginia Gross State Product ("GSP"), electric prices, natural gas prices, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Industrial Sales equation:** Employment in manufacturing, electric prices, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Public Authorities Sales equation:** Employment for Public Authority, number of customers, weather, billing days, and calendar month variables to capture seasonal impacts.
- **Street and Traffic Lighting Sales equation:** Number of residential customers and calendar month variables to capture seasonal impacts.
- **Wholesale Customers and Other LSEs Sales equations:** A measure of non-weather sensitive load derived from the residential equation, heating and air-conditioning appliance stocks, number of days in the month, weather, and calendar month variables to capture seasonal and other effects.

The system model utilizes hourly DOM Zone load data and is estimated in two stages. In the first stage, the DOM Zone load is modeled as a function of time trend variables and a detailed specification of weather involving interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations. The parameter estimates from the first stage are used to construct two composite weather variables, one to capture heating load and one to capture cooling load. In addition to the two weather concepts derived from the first stage, the second stage equation uses estimates of non-weather sensitive load derived from the sales model and residential heating and cooling appliance stocks as explanatory variables. The hourly model also uses calendar month variables to capture time of day, day of week, holiday, other seasonal effects and unusual events such as hurricanes. Separate equations are estimated for each hour of the day.

Hourly models for wholesale customers and other LSEs within the DOM Zone are also modeled as a function of the DOM Zone load since they face similar weather and economic activity. LSE peaks and energy are based on a monthly 10-year average percentage. These percentages are then applied to the forecasted zonal peaks and energy to calculate LSE peaks and energy. The DOM LSE load is derived by subtracting the other LSEs from the DOM Zone load. DOM LSE load and firm contractual obligations are used as the total load obligation for the purpose of this 2016 Plan.

Forecasts are produced by simulating the model over actual weather data from the past 30 years along with projected economic conditions. Sales estimates from the sales model and energy output estimates from the system model are compared and reconciled appropriately in the development of the final sales, energy, and peak demand forecast that is utilized in this 2016 Plan.

2.2 HISTORY & FORECAST BY CUSTOMER CLASS & ASSUMPTIONS

The Company is typically a summer peaking system; however, during the winter period of both 2014 and 2015, all-time DOM Zone peaks were set at 19,785 MW and 21,651 MW respectively. The historical DOM Zone summer peak growth rate has averaged about 1.2% annually over 2001 - 2015. The annual average energy growth rate over the same period is approximately 1.3%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figure 2.2.1 and Figure 2.2.2. Figure 2.2.1 also reflects the actual winter peak demand. DOM LSE peak and energy requirements are both estimated to grow annually at approximately 1.5% throughout the Planning Period. Additionally, a 10-year history and 15-year forecast of sales and customer count at the system level, as well as a breakdown at Virginia and North Carolina levels are provided in Appendices 2A to 2F. Appendix 2G provides a summary of the summer and winter peaks used in the development of this 2016 Plan. Finally, the three-year historical load and 15-year projected load for wholesale customers are provided in Appendix 3L.

Figure 2.2.1 - DOM Zone Peak Load

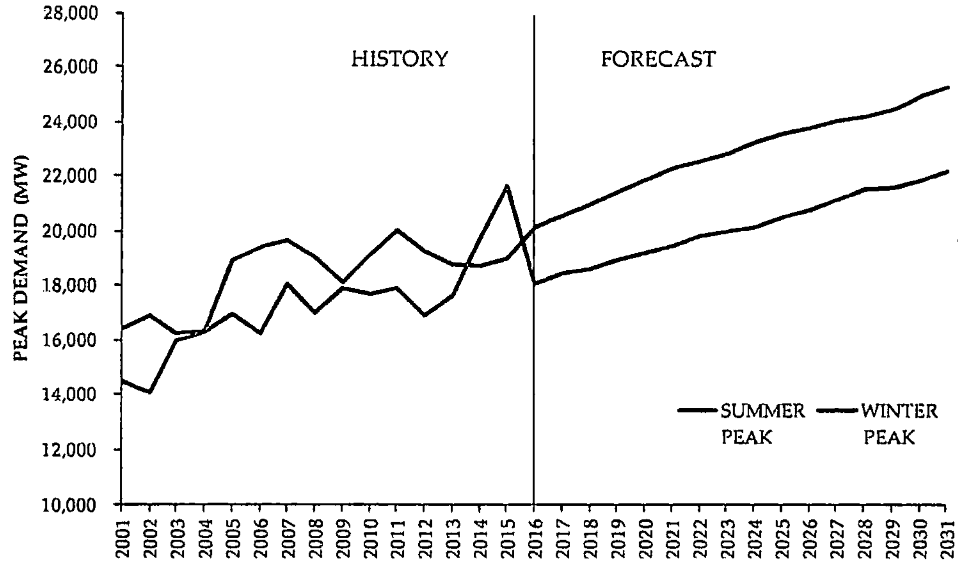


Figure 2.2.2 - DOM Zone Annual Energy

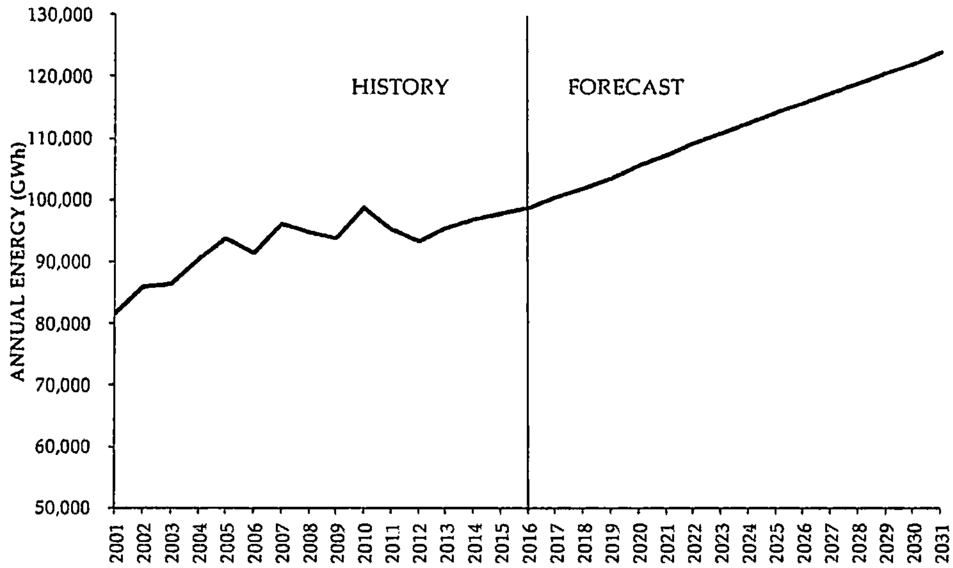


Figure 2.2.3 summarizes the final forecast of energy sales and peak load over the next 15 years. The Company's wholesale and retail customer energy sales are estimated to grow at annual rates of approximately 0.6% and 1.7%, respectively, over the Planning Period as shown in Figure 2.2.3. Historical and projected growth rates can diverge for a number of reasons, including weather and economic conditions.

Figure 2.2.3 - Summary of the Energy Sales & Peak Load Forecast

	2016	2031	Compound Annual Growth Rate (%) 2016 - 2031
DOMINION LSE			
TOTAL ENERGY SALES (GWh)	82,329	105,068	1.6%
Retail	80,797	103,383	1.7%
Residential	30,683	38,467	1.5%
Commercial	31,037	45,135	2.5%
Industrial	8,421	7,553	-0.7%
Public Authorities	10,363	11,868	0.9%
Street and Traffic Lighting	294	360	1.4%
Wholesale (Resale)	1,531	1,684	0.6%
SEASONAL PEAK (MW)			
Summer	17,620	22,103	1.5%
Winter	15,612	19,127	1.4%
ENERGY OUTPUT (GWh)	86,684	108,636	1.5%
DOMINION ZONE			
SEASONAL PEAK (MW)			
Summer	20,127	25,249	1.5%
Winter	18,090	22,162	1.4%
ENERGY OUTPUT (GWh)	98,868	123,900	1.5%

Note: All sales and peak load have not been reduced for the impact of DSM.

Figures 2.2.4 and 2.2.5 provide a comparison of DOM Zone summer peak load and energy forecasts included in the 2015 Plan, 2016 Plan, and PJM's load forecast for the DOM Zone from its 2015 and 2016 Load Forecast Reports.[3]

[3] See www.pjm.com/~/media/documents/reports/2015-load-forecast-report.ashx; see also http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx

Figure 2.2.4 - DOM Zone Peak Load Comparison

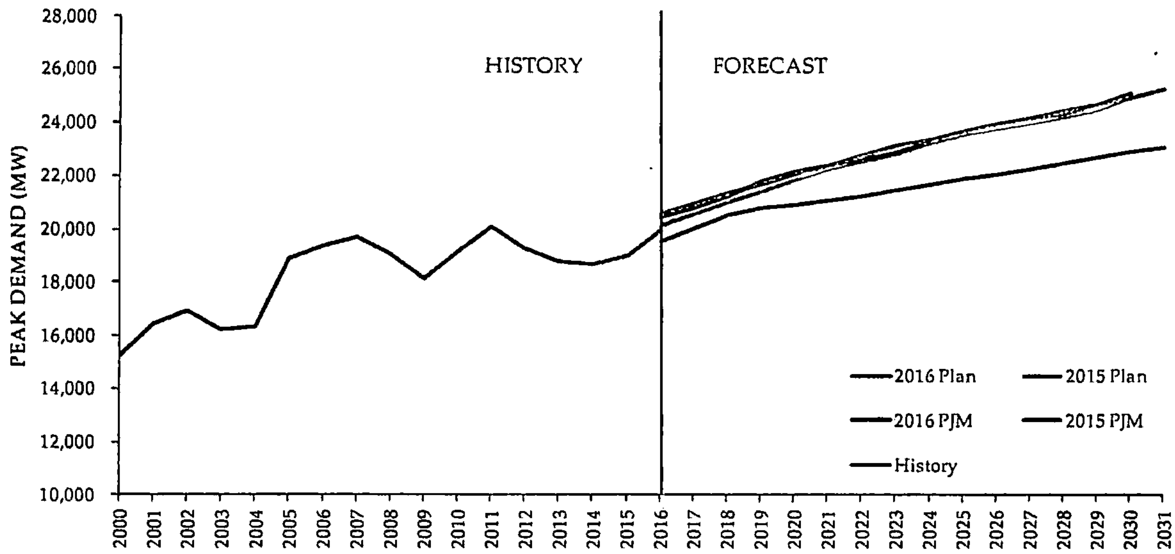
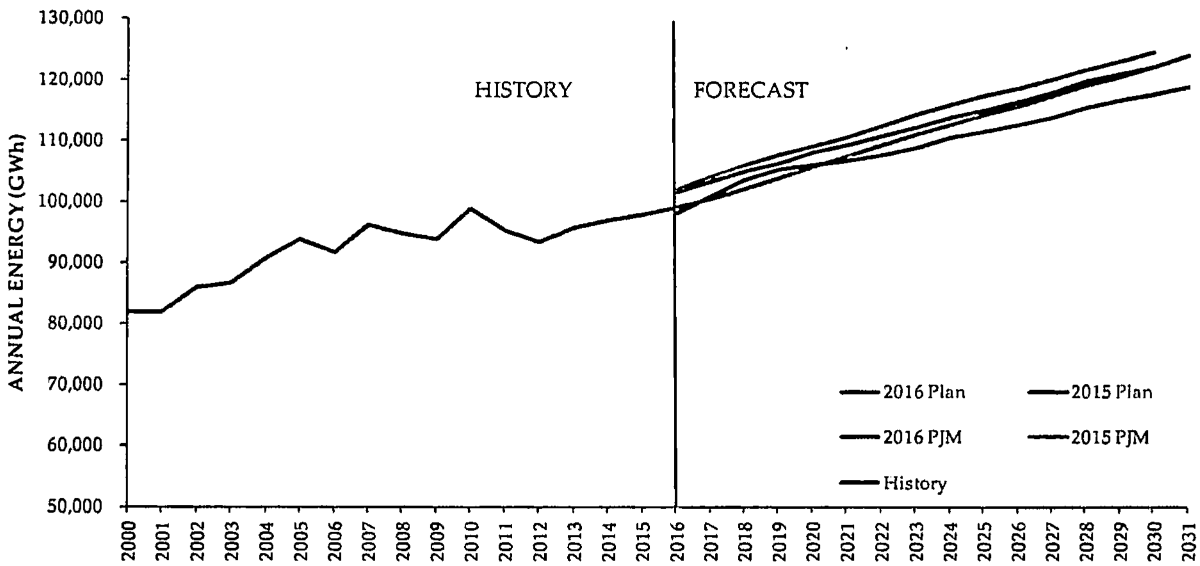


Figure 2.2.5 - DOM Zone Annual Energy Comparison



The Company made an adjustment to its load forecasting to reflect data center growth (both new and expanded campuses) contributing to summer peak and hourly loads starting in 2016. The estimate is a combination of the Company's internal forecast and a study performed by Quanta Technology, Inc. With that exception, the Company's IRP load forecasting methodology has remained consistent over the years, while PJM's 2016 load forecasting methodology underwent significant changes from what was used in 2015. Key changes in PJM's 2016 load forecast include the following:

- The simulation for normal weather was shortened from 41 years to 21 years (1994-2014).
- Variables were added to represent trends in equipment/appliance saturation and energy efficiency.
- The economic region for Virginia was changed to a GSP to reflect growth in Northern Virginia. PJM previously used three metropolitan service areas in Virginia (Richmond, Norfolk, and Roanoke).
- Solar distributed generation was incorporated in the historical load data used to estimate the model. PJM now includes a separately-derived solar forecast to adjust its load forecast.

There have always been many differences between PJM's and the Company's forecasting models and methodologies. Key differences this year include:

- The Company's forecast is based on a "bottom-up approach" and consists of two regression models, one based on hourly load data and the other based on actual customer sales data by class. PJM's forecasting model is based on a "top down approach" using daily energy and daily peak loads.
- The Company's customer sales model includes price elasticity of demand, whereas PJM's model does not.
- The Company's model uses 30 years of historical data to assess normal weather, whereas PJM's model now uses 21 years of historical weather.
- The model estimation period also differs – the Company uses 30 years while PJM's estimation period runs from January 1998 through August 2015.

The economic and demographic assumptions that were used in the Company's load forecasting models were supplied by Moody's Economy.com, prepared in September 2015, and are included as Appendix 2K. Figure 2.2.6 summarizes the economic variables used to develop the sales and peak load forecasts used in this 2016 Plan.

Figure 2.2.6 - Major Assumptions for the Energy Sales & Peak Demand Model

	2016	2031	Compound Annual Growth Rate (%) 2016 - 2031
DEMOGRAPHIC:			
Customers (000)			
Residential	2,275	2,723	1.21%
Commercial	241	279	0.96%
Population (000)	8,460	9,457	0.75%
ECONOMIC:			
Employment (000)			
State & Local Government	542	608	0.76%
Manufacturing	235	204	-0.94%
Government	712	778	0.59%
Income ($)			
Per Capita Real disposable	42,738	54,429	1.63%
Price Index			
Consumer Price (1982-1984 = 100)	242	345	2.40%
VA Gross State Product (GSP)	451	616	2.09%

The forecast for the Virginia economy is a key driver in the Company's energy sales and load forecasts. Like most states, the Virginia economy was adversely impacted by the recession of 2007 - 2009. As compared to other states, however, the Virginia economy was also negatively impacted by federal government budget cuts of 2013 that resulted from the sequestration. This latter event further adversely affected Virginia due to its dependency on federal government spending, particularly in the area of defense. In spite of these economic hurdles, the Virginia economy continued to grow at an annual average real gross domestic product growth rate of approximately 0.7% during the 2007 through 2014 timeframe. Furthermore, during that same time period, Virginia's annual unemployment rate averaged approximately 2% below the national rate. As of December 2015, the seasonally-adjusted unemployment rate in Virginia approached 4.2%, approximately 0.8% below the national unemployment rate.

Going forward, the Virginia economy is expected to rebound considerably within the Planning Period. The 2015 Budget Bill approved by the President and the U.S. Congress has significantly increased the level of federal defense spending for fiscal years 2016 and 2017, which should benefit the Virginia economy. The Commonwealth has also been aggressive in its economic development efforts, a major priority for Virginia state government and the current Governor.

Housing starts and associated new homes are significant contributors to electric sales growth in the Company's service territory. The sector saw significant year-over-year declines in the construction of new homes from 2006 through 2010 and began showing improvements in 2012. According to

Moody's, Virginia is expected to show significant improvement in housing starts in 2017, which is reflected as new customers in the load forecast.

Another driver of energy sales and load forecasts in the Company's service territory is new and existing data centers. The Company has seen significant interest in data centers locating in Virginia because of its proximity to fiber optic networks as well as low-cost, reliable power sources.

On a long-term basis, the economic outlook for Virginia remains positive. Over the next 15 years, real per-capita income in the state is expected to grow about 1.6% per year on average, while real GSP is projected to grow more than 2.0% per year on average. During the same period, Virginia's population is expected to grow steadily at an average rate of approximately 0.75% per year. Further, after the Atlantic Coast Pipeline ("ACP") is completed, new industrial, commercial and residential load growth is expected to materialize as additional low-cost natural gas is made available to the geographical region.

2.3 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

The three-year actual and 15-year forecast of summer and winter peak, annual energy, DSM peak and energy, and system capacity are shown in Appendix 2I. Additionally, Appendix 2J provides the reserve margins for a three-year actual and 15-year forecast.

2.4 ECONOMIC DEVELOPMENT RATES

As of March 1, 2016, the Company has four customers in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 28 MW. There are no customers in Virginia under a self-generation deferral rate.

As of March 1, 2016, the Company has one customer in North Carolina receiving service under economic development rates with approximately 1 MW of load. There are no customers in North Carolina under a self-generation deferral rate.

2.5 RESIDENTIAL AND NON-RESIDENTIAL RATE DESIGN ANALYSIS

SB 956

Pursuant to the enactment clause of SB 956[4] and the SCC's Final Order on the 2011 Plan (Case No. PUE-2011-00092), the Company developed a rate design analysis to: 1) address the appropriateness of a declining block residential rate for winter months; and 2) identify potential, generalized rate designs.

Additionally, in its Final Orders on the 2013 Plan (Case No. PUE-2013-00088) and 2015 Plan (Case No. PUE-2015-00035), the SCC addressed the rate design analysis and directed the Company to consider further rate design issues in subsequent Plans, including directives to:

- Continue to model and refine alternative rate design proposals, including alternative rate designs for customer classes in addition to the residential class;

---

[4] 2013 Va. Acts of Assembly, Ch. 721, Enactment Clause 1 (approved March 25, 2013, effective July 1, 2013).

- Examine the appropriateness of the residential winter declining block rate and present other potential alternatives for the residential winter declining block rate;
- Analyze how alternative rate designs may impact demand and the Company's resource planning process due to price elasticity;
- Continue to report on a residential rate design alternative that includes a flat winter generation rate, an increased inclining summer generation rate, and no changes to distribution rates;
- Continue to report on a residential rate design alternative that includes an increased differential between summer and winter rates for residential customers above the 800 kilowatt-hour ("kWh") block and no change in distribution rates;
- Continue to report on alternative GS-1 rate designs;
- Expand its analysis of alternative rate designs to other non-residential rate classes;
- Investigate an alternative rate design for Rate Adjustment Clauses ("RACs") that includes a summer rate with an inclining block rate component combined with a flat winter rate;
- Analyze whether maintaining the existing rate structure is in the best interest of residential customers;
- Evaluate options for variable pricing models that could incent customers to shift consumption away from peak times to reduce costs and emissions; and
- Evaluate and include various rate-design proposals as part of the mix of DSM-related compliance options that it will be modeling for next May's Plan filing.

2.5.1 RESIDENTIAL RATE SCHEDULE 1 BACKGROUND

The development of the residential rate structure was designed to: 1) reduce the divergence of summer and winter peaks;[5] and 2) enhance the efficiency of the Company's infrastructure by fully utilizing additional generation capacity that is available in the winter due to the level of summer generation capacity required for reliability purposes. This was accomplished through the creation of a summer winter differential which provided the tail block in the summer months that would increase from the first block. To achieve this increase in the summer, revenue was taken from the tail block in the non-summer months, which resulted in a lower non-summer tail block rate.

2.5.2 ALTERNATIVE RATE DESIGN ANALYSIS

The Company's Customer Rates Group developed five alternative rate designs to be used as model inputs to its load forecasting models. All alternative rate designs are revenue neutral.

[5] The Company's annual peak demand for electricity typically occurs in the four-month summer period of June through September, primarily due to loads associated with air conditioning. However, the Company has recorded winter peaks in 2014 and 2015, with an all-time record breaking peak load of 18,688 MW on Friday, February 20, 2015, due to extreme cold weather experienced over several days.

Alternative Residential Rate Design Analysis to the Company's Existing Base Rates:

- Study A: Flat winter generation rate and inclining summer generation rate; and
- Study B: Increased differential between summer and winter generation rates for residential customers above the 800 kWh block; i.e., an increase in summer rates and a decrease in winter rates for residential customers using more than 800 kWh per month with no changes to distribution rates.

Alternative Residential Rate Design for RACs Only:

- Study C: Alternative rate analysis for Schedule 1;
- Study D: Alternative rate analysis for flat winter generation rate and increased inclining summer generation rate; and
- Study E: Alternative rate analysis for increased differential between summer and winter rates for residential customers above the 800 kWh block with no changes to distribution rates.

Figure 2.5.2.1 reflects the sensitivities for each of the alternative residential rate designs compared against existing rates. The Company's existing Schedule 1 residential rates are included in the basecase for all Studied Plans. For each alternative residential rate studied, the impact on the overall net present value ("NPV") of each Studied Plan is reflected accordingly. For example, compared to existing Schedule 1 residential rates in the Plan A: No CO_2 Limit, Residential Study A (Flat winter generation rate and inclining summer generation rate) will be 0.21% less costly. Also, compared to the existing Schedule 1 residential rates for Plan E: Mass-Based Emissions Cap (existing and new units), Residential Study E (Increased differential between summer and winter rates with an alternative RAC design for the generation riders) will be 0.21% less costly (26.61% - 26.40%).

Figure 2.5.2.1 – Residential Rate Study Comparison

		Subject to the EPA's Clean Power Plan			
Study	Plan A: No CO_2 Limit	Plan B: Intensity-Based Dual Rate	Plan C: Intensity-Based State Average	Plan D: Mass-Based Emissions Cap (existing units only)	Plan E: Mass-Based Emissions Cap (existing and new units)
Base	★	10.68%	12.37%	11.57%	26.61%
A	-0.21%	10.40%	12.12%	11.26%	26.29%
B	-0.15%	10.45%	12.16%	11.31%	26.33%
C	-0.10%	10.50%	12.19%	11.35%	26.35%
D	-0.09%	10.50%	12.20%	11.35%	26.35%
E	-0.05%	10.55%	12.25%	11.40%	26.40%

Note: The star represents the cost for the No CO_2 Cost scenario under the Plan A: No CO_2 Limit.

2.5.3 RESULTS OF THE ALTERNATIVE RATE DESIGN ANALYSIS

The modeling results follow expectations such that increases in prices lead to lower demand, and decreases in prices lead to higher demand.

> 1% increase in the average residential price of electricity would reduce average consumption by approximately 0.06%.

The average calculation of elasticity over the modeled sensitivities for Schedule 1 customers is approximately 0.06, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.06%. The elasticity suggests that increases in price, holding all other variables constant, will place downward pressure on total sales and peak levels. For more detail regarding the Alternative Residential Rate Analysis, see Appendix 2L.

2.5.4 ALTERNATIVE NON-RESIDENTIAL SCHEDULE GS-1 AND SCHEDULE 10 RATE DESIGN

The Company's Customer Rates Group developed six alternative non-residential rate designs to be used as model inputs to the Company's load forecasting models. Alternative Non-Residential GS-1 and Schedule 10 rate designs were intended to be revenue neutral on a rate design basis, and were developed to provide additional clarity to long-term rate impacts as determined by the Company's long-term forecasting models.

The Company considered alternative rate designs for GS-3 (Secondary Voltage) and GS-4 (Primary Voltage) that would extend the peak period rate into the weekend, but these rates are properly designed for customers. Customers on these rates have a demand charge that sends a price signal to manage their electricity consumption. In addition, these customers are typically high load factor customers and are not likely to respond to a peak rate extended into the weekend. Rate Schedule GS-1 was chosen for this analysis because the Company does not offer a non-pilot time-of-use ("TOU") alternative for the GS-1 customer class. The six rate designs used to compare against the current declining block rates in the winter months are listed below.

Alternative Non-Residential GS-1 Rate Designs to the Company's Existing Base Rates:

- Study A: Flat rates during summer and winter for both distribution and generation;
- Study B: Inclining block rates during summer and winter for generation with flat distribution rates;
- Study C: Flat winter generation rates with no change in the existing summer generation rates or existing distribution rates;
- Study D: Increased differential between summer and winter rates for commercial customers above the 1,400 kWh block; i.e., an increase in summer rates and a decrease in winter rates for commercial customers using more than 1,400 kWh per month with no changes to distribution rates; and
- Study E: Flat winter generation rate and increased inclining summer generation rate.

Alternative Non-Residential Rate Design for Schedule 10:

- Study F: Increase the on-peak rate for "A" days during the peak on and off-peak seasons with no changes to the off-peak rate. Reduce the peak and off-peak rates for "B" and "C" days for both the peak and off-peak seasons.

Figure 2.5.4.1 reflects the sensitivities for each of the alternative non-residential rate designs compared against existing GS-1 rates (Studies A-E) and Schedule 10 (Study F). The Company's existing GS-1 rates and Schedule 10 are included in the basecase for all Studied Plans. For each alternative non-residential rate studied, the impact on the overall NPV of each Studied Plan is reflected accordingly. For example, compared to existing GS-1 non-residential rates in the Plan A: No CO_2 Limit, Non-Residential Study A (Flat rates during the summer and winter for both distribution and generation) will be 0.03% less expensive. Another example would be that compared to the existing Schedule 10 non-residential rates for Plan E: Mass-Based Emissions Cap (existing and new units), Non-Residential Study F (Increase the on-peak rate for "A" days during the peak and off-peak seasons with no change to the off-peak rate and reduce the peak and off-peak rates for "B" and "C" days) will be 0.17% less costly (26.61% - 26.44%).

Figure 2.5.4.1 – Non-Residential Rate Study Comparison

		Subject to the EPA's Clean Power Plan			
	Plan A:	Plan B:	Plan C:	Plan D:	Plan E:
Study	No CO_2 Limit	Intensity-Based Dual Rate	Intensity-Based State Average	Mass-Based Emissions Cap (existing units only)	Mass-Based Emissions Cap (existing and new units)
Base	★	10.68%	12.37%	11.57%	26.61%
A	-0.03%	10.57%	12.26%	11.41%	26.41%
B	-0.04%	10.56%	12.26%	11.41%	26.41%
C	-0.04%	10.56%	12.25%	11.41%	26.41%
D	-0.05%	10.56%	12.25%	11.40%	26.41%
E	-0.05%	10.55%	12.25%	11.40%	26.40%
F	-0.07%	10.56%	12.27%	11.41%	26.44%

Note: The star represents the cost for the No CO_2 Cost scenario under the Plan A: No CO_2 Limit.

2.5.5 RESULTS OF THE ALTERNATIVE NON-RESIDENTIAL RATE ANALYSIS

The modeling results follow expectations such that increases in prices lead to lower demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities for GS-1 customers is approximately 0.4, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.4%. The average calculation of elasticity over the modeled sensitivities for GS-3 and GS-4 customers on Schedule 10 rates is approximately -0.11, meaning a 1% increase in the average price of electricity on "A" days would reduce average consumption by approximately 0.11%. The elasticity suggests that increases

> 1% increase in the average price of electricity for GS-1 customers would reduce average consumption by approximately 0.4%.
>
> 1% increase in the average price of electricity on "A" days for GS-3 and GS-4 customers on Schedule 10 rates would reduce average consumption by approximately 0.11%.

in price, holding all other variables constant, will place downward pressure on sales and peak levels. Such an impact from recognition of a price elasticity effect on the generation and resource plan should also be recognized in the design of electricity rates. For more detail regarding the Alternative Non-Residential Rate Analysis, see Appendix 2M.

2.5.6 APPROPRIATENESS OF THE DECLINING BLOCK RATE

Based on the results of these studies, the Company maintains that the declining winter block rate continues to be an appropriate rate mechanism to utilize generation capacity efficiently on an annualized basis, control summer peak growth, and keep rates low and affordable, particularly for electric heating customers. While the study results presented begin to reveal correlations and relationships between price and quantity, these analyses should be viewed as initial benchmark studies of alternative rate designs.

Large pricing changes make the model outputs less reliable than would be desired to establish alternative rate designs that may be considered just and reasonable. Additionally, the studies contemplate an instantaneous shift in rate design, rather than a long-term incremental approach to rate changes which allows customers to react and avoid large rate increases. For example, customers' investments in long-term electric-based infrastructure, such as heat pumps, could be significantly impacted under an alternative rate studies in a negative fashion.

Several natural gas utilities also offer declining block rates during winter months. Consideration must be given to the impact that adjusting, or eliminating, declining block rates will have on fuel switching.

The Company continues to support the current rate design for Schedule 1 and believes it is in customers' best interest to not stray far from the current design. The current design does send a price signal to customers to reduce consumption to avoid future capacity obligations. By calling for a more rigorous analysis of the Schedule 1 residential rate design, such analysis would need to consider the types of costs (fixed, demand-related fixed, and variable) that have been incurred and the way such costs are recovered through rates. The current two part rate design in Schedule 1 does not represent an approach to cost recovery through rates consistent with the way that costs have actually been incurred. Distribution costs are fixed and either classified as customer or demand-related. Transmission costs are fixed and are demand-related. The majority of production costs are fixed and demand-related. Fuel costs are variable and are energy-related. Yet over 93% of a 1,000 kWh/month typical residential customer's bill is recovered through charges that vary with kWh consumption. In contrast, for medium and large general service customer classes, the Company's standard tariffs reflect a three-part rate design that is more consistent with the way that costs have actually been incurred.

To address the question about whether the existing rate structure is in the best interest of residential customers, one must consider that there are over 2 million customers taking service on Rate Schedule 1, and any change to the current design structure would be a major undertaking with unknown customer impacts and create questions about customer acceptance. The question of customer acceptance with regard to design changes to Rate Schedule 1 may be a matter of public policy and not solely a question of achieving cost recovery through rates consistent with cost causation.

Proper rate design is guided by many principles and objectives but chief among them should be that rates reasonably recover costs. Important considerations during the rate design process include factors such as:

- the impact of rate design on customer bills;
- the stability of customer bills;
- the difference in utility system costs based upon seasons, day of the week, and time of day;
- cost control through encouraging price response to avoid future utility system costs;
- the impact on bills for customers using various methods of space conditioning;
- the availability of other competitive fuel sources to provide space conditioning;
- the availability of voluntary/optional rate schedules within each customer class as it relates to recovery of the revenue requirement apportioned to the class;
- the competitiveness of customer bills (and therefore rates) with other utilities and, in particular, with regard to the southeastern peer group;
- delivery and measurement technologies available for use to measure usage for the purpose of billing customers; and
- other factors and policies historically determined by the SCC to be appropriate in establishing rates.

Underlying all of these considerations, rate design should provide the means to recover just and reasonable utility system costs in a manner that is: (i) consistent with the way costs are incurred; (ii) fair to the entire body of customers; (iii) fair to each customer class; (iv) fair to customers within an individual class; and (v) fair to the utility's shareholders.

2.5.7 MODEL AN ALTERNATIVE RATE DESIGN (RESIDENTIAL DYNAMIC PRICING) AS A LOAD REDUCER AS PART OF THE MIX OF DSM-RELATED COMPLIANCE OPTIONS

This study presents the results of an analysis to implement dynamic pricing in lieu of Schedule 1 rates for the residential population in Virginia. The Company examined energy usage data from approximately 20,000 residential customers with Advanced Metering Infrastructure ("AMI") meters on Schedule 1 rates and developed a regression model to predict the effects of different pricing signals on peak and energy demand for the calendar year 2015. The Company used the same cooling/heating season periods, "A/B/C" day classifications and dynamic rates that were used in the Company's Dynamic Pricing Pilot ("DPP"). Unfortunately, this regression modeling approach was necessary because data obtained from the actual DPP customers resulted in a price elasticity that was counterintuitive because as prices increased, demand increased. This may be the result of data bias due to a small sample size. Given this perceived anomaly in the DPP customer data, the Company elected to complete this analysis using the regression modeling method described above.

The dynamic pricing regression modeling results follow expectations such that increases in prices lead to lower peak demand, and decreases in prices lead to higher demand. The average calculation of elasticity over the modeled sensitivities for residential dynamic pricing is approximately -0.75, meaning a 1% increase in the average price of electricity would reduce average consumption by approximately 0.75%. The elasticity suggests that increases in price, holding all other variables constant, will place downward pressure on system peak levels. Econometric analysis of the residential response to different price signals effectively suggests a decrease in peak demand and usage during peak months and a net kWh usage increase during shoulder months. The -0.75 price elasticity determined in this analysis is extraordinarily high, however, and also questionable as to its validity. This is likely the result of developing the regression model with data from customers who are currently being serviced under Schedule 1 rates. A more appropriate model would be one developed using data from customers that are currently on DPP rates but as was mentioned previously, the results from the model using the actual data from DPP customers produced counterintuitive results and could not be utilized in this analysis.

> 1% increase in the average residential price of electricity would decrease average consumption of dynamic pricing customers by approximately 0.75%.

For more detail regarding the Alternative Residential Dynamic Pricing Rate Analysis, see Appendix 2N.

Figure 2.5.7.1 reflects the sensitivities for the alternative residential dynamic pricing rate design compared against existing rates. The Company's existing Schedule 1 residential rates are included in the basecase for all Studied Plans. The impact on the NPV of the Studied Plan is reflected accordingly. For example, compared to existing Schedule 1 residential rates in the Plan A: No CO_2 Limit, the Residential Dynamic Pricing Rate will be 0.15% more costly. Also, compared to the existing Schedule 1 residential rates for Plan E: Mass-Based Emissions Cap (existing and new units), the Residential Dynamic Pricing Rate will be 0.08% more costly (26.69% - 26.61%).

Figure 2.5.7.1 – Residential Dynamic Pricing Rate Study Comparison

		Subject to the EPA's Clean Power Plan			
	Plan A:	Plan B:	Plan C:	Plan D:	Plan E:
Study	No CO_2 Limit	Intensity-Based Dual Rate	Intensity-Based State Average	Mass-Based Emissions Cap (existing units only)	Mass-Based Emissions Cap (existing and new units)
Base	★	10.68%	12.37%	11.57%	26.61%
Dynamic Pricing	0.15%	10.78%	12.50%	11.64%	26.69%

Note: The star represents the cost for the No CO_2 Cost scenario under the Plan A: No CO_2 Limit.

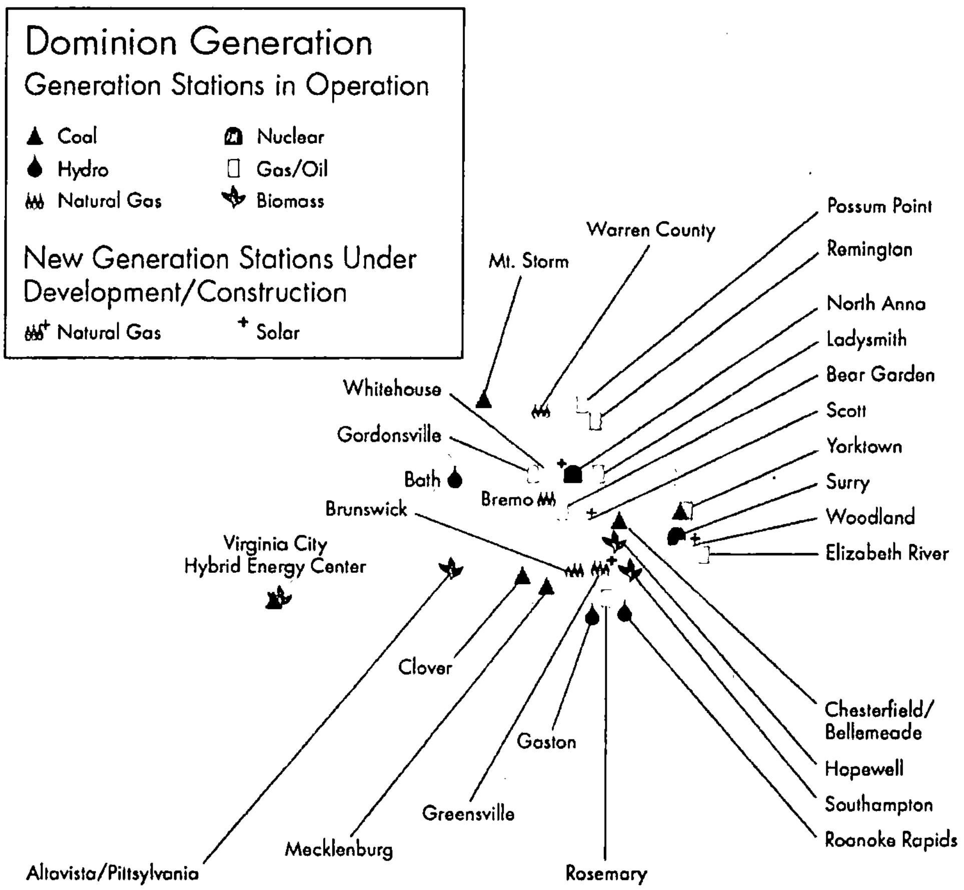
CHAPTER 3 – EXISTING & PROPOSED RESOURCES

3.1 SUPPLY-SIDE RESOURCES

3.1.1 EXISTING GENERATION

The Company's existing generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 3.1.1.1. This diverse fleet of 99 generation units includes 4 nuclear, 14 coal, 4 natural gas-steam, 10 CCs, 41 CTs, 4 biomass, 2 heavy oil, 6 pumped storage, and 14 hydro units with a total summer capacity of approximately 19,829 MW.[6] The Company's continuing operational goal is to manage this fleet in a manner that provides reliable, cost-effective service under varying load conditions.

Figure 3.1.1.1 - Dominion Virginia Power Generation Resources

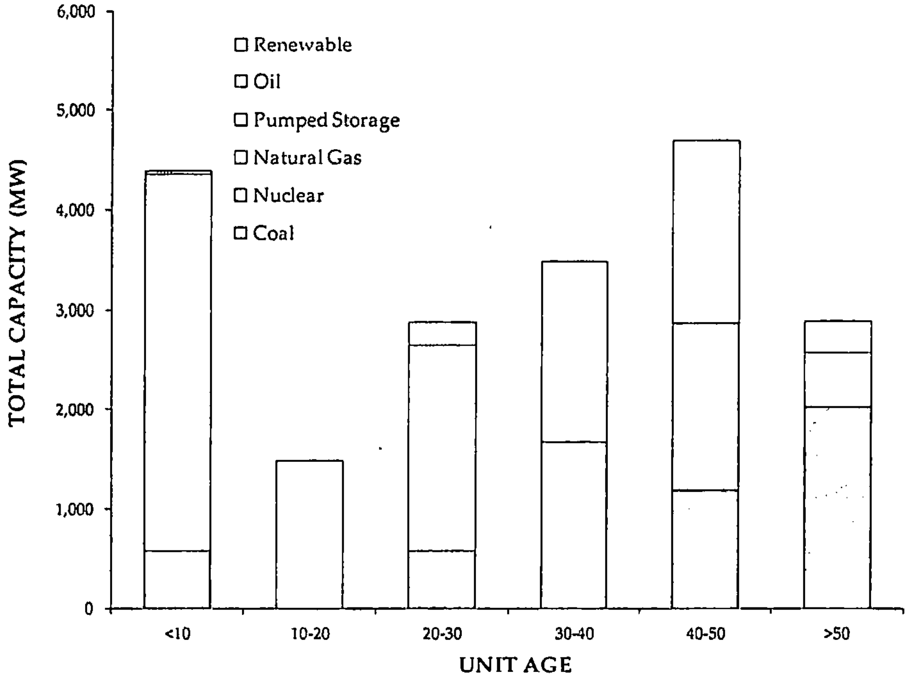


The Company owns a variety of generation resources that operate using a diverse set of fuels. The largest proportion of the Company's generation resources has operated for 40 to 50 years, followed by a large number of units that have operated for less than 10 years and units that have operated for 30 to 40 years. Figure 3.1.1.2 shows the demographics of the entire existing generation fleet.

---

[6] All references to MW in Chapter 3 refer to summer capacity unless otherwise noted. Winter capacities for Company-owned generation units are listed in Appendix 3A.

Figure 3.1.1.2 - Generation Fleet Demographics



Note: Renewable resources constitute biomass, wind, solar and hydro units.

Figure 3.1.1.3 illustrates that the Company's existing generation fleet is comprised of a mix of generation resources with varying operating characteristics and fueling requirements. The Company also has contracted 1,277 MW of fossil-burning and renewable NUGs, which provide firm capacity as well as associated energy and ancillary services to meet the Company's load requirements. Appendix 3B lists all of the NUGs in the 2016 Plan. The Company's planning process strives to maintain a diverse portfolio of capacity and energy resources to meet its customers' needs.

Figure 3.1.1.3 - 2016 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity[1] (MW)	Percentage (%)
Coal	4,372	20.7%
Nuclear	3,349	15.9%
Natural Gas	7,878	37.3%
Pumped Storage	1,808	8.6%
Oil	1,833	8.7%
Renewable	590	2.8%
NUG - Coal	627	3.0%
NUG - Natural Gas Turbine	605	2.9%
NUG - Solar	45	0.2%
NUG Contracted	1,277	6.1%
Company Owned	19,829	93.9%
Company Owned and NUG Contracted	21,107	100.0%
Purchases	-	0.0%
Total	21,107	100.0%

Note: 1) Represents firm capacity towards reserve margin.

Due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is economically dispatched by PJM within its larger footprint, ensuring that customers in the Company's service area receive the benefit from all resources in the PJM power pool regardless of whether the source of electricity is Company-owned, contracted, or third-party units. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 3.1.1.4 and 3.1.1.5 provide the Company's 2015 actual capacity and energy mix.

Figure 3.1.1.4 - 2015 Actual Capacity Mix

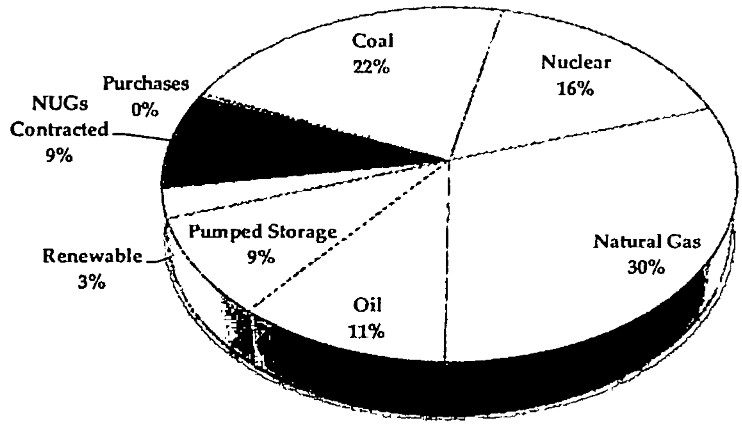
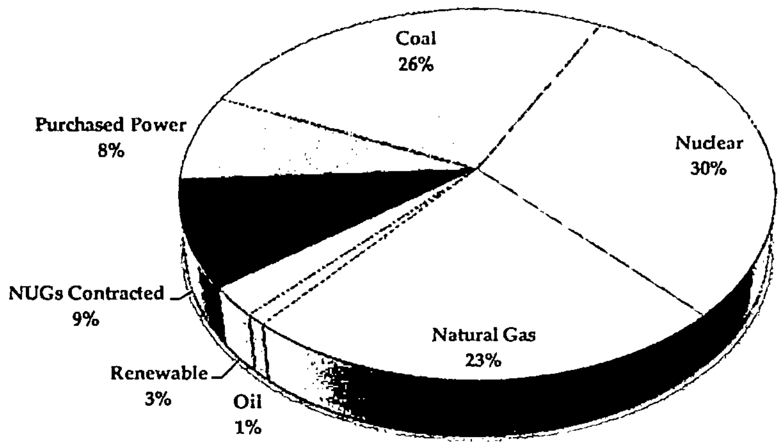


Figure 3.1.1.5 - 2015 Actual Energy Mix



Note: Pumped storage is not shown because it is net negative to the Company's energy mix.

Appendices 3A, 3C, 3D, and 3E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Additionally, Appendix 3F provides a summary of the existing capacity, by fuel class, and NUGs. Appendices 3G and 3H provide energy generation by type as well as the system output mix. Appendix 3B provides a listing of other generation units including NUGs, behind-the-meter generation ("BTMG"), and customer-owned generation units.

3.1.2 EXISTING RENEWABLE RESOURCES

The Company currently owns and operates 590 MW of renewable resources, including approximately 236 MW of biomass generating facilities. The Virginia City Hybrid Energy Center ("VCHEC") (610 MW) is expected to consume renewable biomass fuel of up to 5.5% (34 MW) in 2016 and gradually increase that level to 10% (61 MW) by 2021. The Company also owns and operates four hydro facilities: Gaston Hydro Station (220 MW), Roanoke Rapids Hydro Station (95 MW), Cushaw Hydro Station (2 MW), and North Anna Hydro Station (1 MW). Additionally, the Company completed the first installations of its SPP in 2014.

Renewable Energy Rates and Programs

The Company has implemented various rates and programs to increase the availability of renewable options, as summarized in Figure 3.1.2.1.

Figure 3.1.2.1 - Renewable Rates & Programs

Renewable	Supplier			Customer Group				Size Limitations	
	Company-Owned	Participant-Owned	Third-Party Owned	Residential	Small Commercial	Large Commercial	Industrial	Individual	Aggregate
Solar Partnership Program	X	-	-	-	X	X	X	500 kW – 2 MW	30 MW
Solar Purchase Program	-	X	-	X	X	-	-	Res: ≤20 kW Non-Res: ≤50 kW	3 MW
Green Power Program	-	-	X	X	X	X	X	None	None
Rate Schedule RG	-	-	X	-	-	X	X	1 million kWh/yr Min 24 million kWh/yr Max	240 million kWh/yr or 100 Customers
Third-Party PPA Pilot	-	-	X	X	X	X	X	1 kW - 1 MW	50 MW
Net Metering	-	X	-	X	X	X	X	Res: 20 kW Non-Res: 1 MW	1% of Adjusted Peak Load for Prior Year
Agricultural Net Metering	-	X	-	-	X	X	X	≤500 kW	Within Net Metering Cap

Note: Eligibility and participation subject to individual program parameters.

Solar Partnership Program

The Solar Partnership Program (or SPP) is a demonstration program in which the Company is authorized to construct and operate up to 30 MW (DC) of Company-owned solar DG facilities on leased commercial and industrial customer property and in community settings. This is intended as a five-year demonstration program to study the benefits and impacts of solar DG on targeted distribution circuits. Current installed capacity of the program is 4.0 MW. More information can be found on the SCC website under Case No. PUE-2011-00117 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/solar-partnership-program.

Solar Purchase Program

The Solar Purchase Program facilitates customer-owned solar DG as an alternative to net metering. Under this program, the Company purchases energy output, including all environmental attributes and associated renewable energy certificates ("RECs"), from participants at a premium rate under Rate Schedule SP, a voluntary experimental rate, for a period of five years. The Company's Green Power Program® directly supports the Solar Purchase Program through the purchase and retirement of produced solar RECs. There are approximately 100 participants with an installed capacity of 1.3

MW. More information can be found on the SCC website under Case No. PUE-2012-00064 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/solar-purchase-program.

Green Power Program®

The Company's Green Power Program® allows customers to promote renewable energy by purchasing, through the Company, RECs in discrete blocks equal to 100% of their usage or a portion of their usage. The Company purchases and retires RECs on behalf of participants. There are approximately 26,500 customers participating in this program. More information can be found on the SCC website under Case No. PUE-2008-00044 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/dominion-green-power.

Rate Schedule RG

Rate Schedule RG provides qualifying large non-residential customers in Virginia with the option to meet a greater portion of their energy requirements with renewable energy. Eligible customers sign a contract for the Company to purchase additional amounts of renewable energy from a third party as determined by the customer. More information can be found on the SCC website under Case No. PUE-2012-00142 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/schedule-rg.

Renewable Energy (Third-Party PPA) Pilot

The SCC's Renewable Energy Pilot Program allows qualified customers to enter into a Power Purchase Agreement ("PPA") with a third-party renewable energy supplier. The energy supplied must come from a wind or solar generator located on the customer's premise. Eight customers have provided notices of participation in this Pilot. More information can be found on the SCC website under Case No. PUE-2013-00045 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/renewable-energy-pilot-program.

Net Metering

Net Metering allows for eligible customer generators producing renewable generation to offset their own electricity usage consistent with Va. Code § 56-594 and SCC regulations governing net metering in the Virginia Administrative Code (20 VAC 5-315-10 *et seq.*) and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/traditional-net-metering. There are approximately 1,700 net metering customer-generators with a total installed capacity of approximately 12.8 MW.

Agricultural Net Metering

Agricultural Net Metering allows agricultural customers to net meter across multiple accounts on contiguous property. More information can be found on the SCC website under Case No. PUE-2014-00003 and on the Company's website: https://www.dom.com/business/dominion-virginia-power/ways-to-save/renewable-energy-programs/agricultural-net-metering.

3.1.3 CHANGES TO EXISTING GENERATION

The Company is fully committed to meeting its customers' energy needs in a manner consistent with a clean environment and supports the establishment of a comprehensive national energy and environmental policy that balances the country's needs for reliable and affordable energy with reasonable minimization of environmental impacts. Cognizant of the effective and anticipated EPA regulations concerning air, water, and solid waste constituents, and particularly the stay of the EPA's CPP regarding CO_2 emissions from existing electric generating units (see Figure 3.1.3.1), the Company continuously evaluates various options with respect to its existing fleet.

As a result, the Company has a balanced portfolio of generating units, including low-emissions nuclear, highly-efficient and clean-burning natural gas, and hydro that has a lower carbon intensity compared to the generation fleet of most other integrated energy companies in the country. As to the Company's coal generators, the majority of those generators are equipped with SO_2 and NO_x controls; however, the remaining small coal-fired units are without sufficient emission controls to comply with effective and anticipated regulatory requirements. The Company's coal-fired units at the Chesterfield, Mt. Storm, Clover, Mecklenburg and VCHEC facilities have flue gas desulfurization environmental controls to control SO_2 emissions. The Company's Chesterfield Units 4, 5 and 6, Mt. Storm, Clover, and VCHEC coal-fired generation units also have selective catalytic reduction ("SCR") or SNCR technology to control NO_x emissions. The Company's biomass units at Pittsylvania, Altavista, Hopewell and Southampton operate SNCRs to reduce NO_x. In addition, the Company's NGCC units at Bellemeade, Bear Garden, Gordonsville, Possum Point and Warren County have SCRs.

Uprates and Derates

Efficiency, generation output, and environmental characteristics of plants are reviewed as part of the Company's normal course of business. Many of the uprates and derates discussed in this section occur during routine maintenance cycles or are associated with standard refurbishment. However, several plant ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations.

Possum Point Unit 6 is a 2x1 CC unit that went into commercial operation in July 2003. A turbine uprate was completed in the spring of 2015, which increased summer capacity from 559 MW to 573 MW.

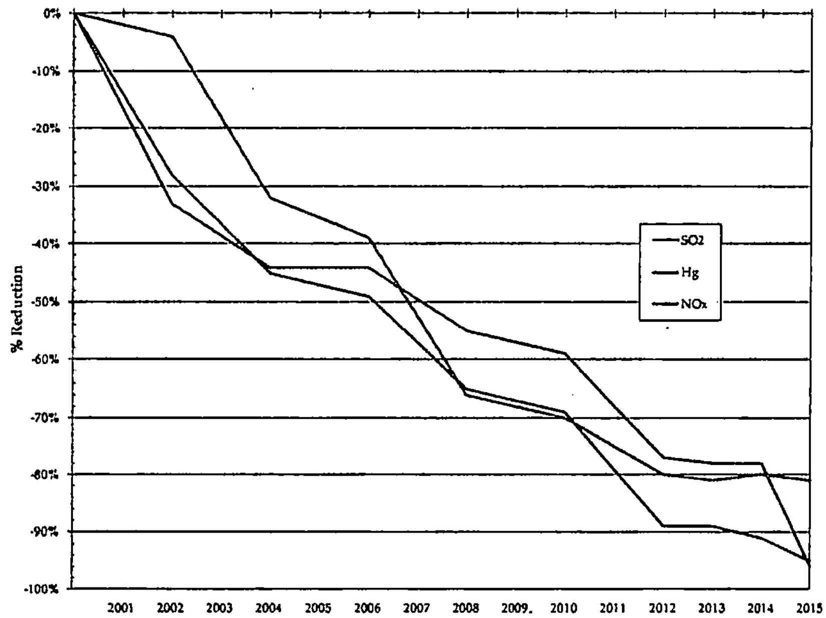
Bear Garden Power Station ("Bear Garden") is a 2x1 CC that was completed in the summer of 2011. A turbine uprate is planned to be completed in the spring of 2017, which will increase summer capacity from 590 MW to 616 MW.

The Company continues to evaluate opportunities for existing unit uprates as a cost-effective means of increasing generating capacity and improving system reliability. Appendix 3I provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

Environmental Performance

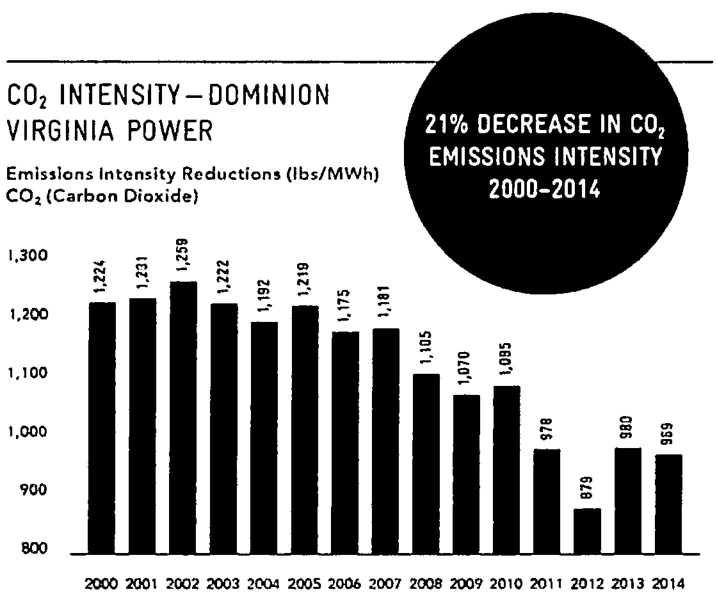
The Company has reduced emissions of SO_2, NO_x, and mercury from its generation fleet over the last decade as reflected in Figure 3.1.3.1.

Figure 3.1.3.1 – Dominion Virginia Power Emission Reductions (lbs/MWh)



Similarly, the Company has reduced emissions of greenhouse gases, including CO_2, through retiring certain at-risk units and building additional efficient and lower-emitting power generating sources. The CO_2 emission reductions from 2000 through 2014 are shown in Figure 3.1.3.2.

Figure 3.1.3.2 – CO_2 Emission Reductions 2000 - 2014



EPA Regulations

There are a significant number of final, proposed, stayed and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. As shown in Figure 3.1.3.3, these regulations are designed to regulate air, solid waste, and water constituents.

Figure 3.1.3.3 - EPA Regulations

Constituent		Key Regulation	Final Rule	Compliance
AIR	Hg/HAPS	Mercury & Air Toxics Standards (1) (MATS)	12/16/2011	4/16/2015 4/16/2017
AIR	SO_2	CSAPR (2)	2011	2015/2017
AIR	SO_2	SO_2 NAAQS	6/2/2010	2018
AIR	NOx	2008 Ozone Standard (75 ppb)	5/2012	2017
AIR	NOx	2015 Ozone Standard (70 ppb)	10/1/2015	2018 - 2019
AIR	NOx	CSAPR (3)	2011	2015/2017
AIR	CO_2	GHG Tailoring Rule	5/2010	2011
AIR	CO_2	EGU NSPS (New)	10/2015	Retro to 1/8/2014
AIR	CO_2	Clean Power Plan (CPP) (4)	10/2015	2022/2030 (4)
AIR	CO_2	EGU NSPS (Modified and Reconstructed)	10/2015	10/23/2015
AIR	CO_2	Federal CO_2 Program (Alternative to CPP)	Uncertain	2023
WASTE	ASH	CCR's	4/17/2015	2018 - 2020
WATER	Water 316b	316b Impingement & Entrainment (5) (6)	5/19/2014	2019
WATER	Water Effluent	Effluent Limitation Guidelines (7)	9/30/2015	11/1/2018

Key: Constituent: Hg: Mercury; HAPS: Hazardous Air Pollutants; SO_2: Sulfur Dioxide; NOx: Nitrogen Oxide; CO_2: Carbon Dioxide; GHG: Greenhouse Gas; Water 316b: Clean Water Act § 316(b) Cooling Water Intake Structures;

Regulation: MATS: Mercury & Air Toxics Standards; CPP: EPA's Clean Power Plan; CSAPR: Cross-State Air Pollution Rule; SO_2 NAAQS: Sulfur Dioxide National Ambient Air Quality Standards; Ozone Std Rev PPB: Ozone Standard Review Parts per Billion; EGU NSPS: Electric Generating Units New Source Performance Standard.

Note: (1) CEC 1-4 retired in December 2014. YT 1-2 to be retired by April 16, 2017 (per provisions of the EPA Administrative Order of April 16, 2016).

(2) SO_2 allowances will be decreased by 50% in 2017. Retired units retain CSAPR allowances for four years. System is expected to have sufficient SO_2 allowances.

(3) Proposed revisions to CSAPR would reduce ozone season NOx allowances by ~55% beginning in 2017. Could have allowance shortfalls as early as 2018 if limits imposed on use of banked allowances. Retired units retain CSAPR allowances for 4 years. System is expected to have sufficient annual NOx allowances.

(4) CPP sets interim targets (2022-2024; 2025-2027; 2028-2029) in addition to 2030 targets. CPP also sets "equivalent" statewide Intensity-Based and Mass-Based interim 2030 targets. CPP is currently stayed.

(5) Rule would not apply to Mt. Storm under the assumption that the plant's man-made lake does not qualify as a "water of the U.S."

(6) 316(b) studies will be due with discharge permit applications beginning in mid-2018. Installation of 316(b) technology requirements will be based on compliance schedules put into discharge permits.

(7) Rule does not apply to simple-cycle CTs or biomass units.

Revised Ozone National Ambient Air Quality Standards ("NAAQS")

In May 2008, the EPA revised the ozone standard from 80 ppb to 75 ppb. Subsequently, in October 2015, the EPA issued a final rule tightening the ozone standard from 75 ppb to 70 ppb. States will have until 2020 or 2021 to develop plans to address the new standard. Until then, the Company is unable to predict whether the new rules will ultimately require additional controls. However, for planning purposes, we have included additional NO_x control equipment in the form of SNCR technology on Possum Point Unit 5 as a potentially feasible control option in 2018. The need to install additional controls for either the 2008 (75 ppb) standard or the revised 2015 (70 ppb) standard will be determined by the Virginia Department of Environmental Quality ("DEQ") assessment of Reasonable Available Control Technology ("RACT") requirements under the Ozone NAAQS SIP. No other power generating units are expected to be impacted by the standards.

Cross-State Air Pollution Rule ("CSAPR")

In December 2015, the EPA published a proposed revision to CSAPR. If finalized as proposed, the revised rule will substantially reduce the CSAPR Phase II ozone season NO_x emission caps in 23 states, including Virginia, West Virginia and North Carolina, which would take effect beginning with the 2017 ozone season. The proposed reductions in state caps would in turn reduce, by approximately 55% overall, the number of allowances the Company's EGUs will receive under the CSAPR Phase II ozone season NO_x program. In addition, the EPA is proposing to discount the use of banked Phase I allowances for compliance in Phase II by applying either a 2:1 or 4:1 surrender ratio. At this time, the Company has not planned for any additional NO_x controls to be installed on any units.

Coal Ash Regulations

In April 2015, the EPA's final rule regulating the management of coal combustion residuals ("CCRs") stored in impoundments (ash ponds) and landfills was published in the Federal Register. This final rule regulates CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store CCRs. The Company currently owns inactive ash ponds, existing ash ponds, and CCR landfills subject to the CCR final rule at eight different facilities. The final rule required the Company to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary. The Company is in the process of complying with all these requirements.

Clean Water Intake Regulations (i.e., Clean Water Act, Section 316(b))

In October 2014, final regulations became effective under Section 316(b) of the Clean Water Act ("CWA"), which govern existing facilities that employ a cooling water intake structure and have flow levels exceeding a minimum threshold, became effective. The rule establishes a national standard for impingement based on seven compliance options. The EPA has delegated entrainment technology decisions to state environmental regulators. State environmental regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost/benefit test and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day. The Company has 11 facilities that may be subject to the regulations, and anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Currently, the Company is evaluating the need or potential for entrainment controls under the final regulations as these decisions will be made on a case-by-case basis by the state regulatory agency after a thorough review of detailed biological, technology, cost and benefit studies. Any new technology requirements will likely be incorporated in discharge permits issued after 2018, and will be installed in accordance with schedules established in those permits. The costs for these additional control technologies could be significant.

Clean Power Plan Overview

On August 3, 2015, the EPA promulgated the final CPP rule to regulate CO_2 emissions from existing power plants under Section 111(d) of the Clean Air Act. The EPA has projected the full implementation of the final rule across all affected states will achieve a 32% reduction in nationwide power plant CO_2 emissions from 2005 levels by 2030. The CPP is designed to start in 2022, with an eight-year interim period, and final targets in 2030. Under the CPP (prior to the Supreme Court stay), states were required to submit initial SIPs by September 6, 2016, but could request an extension to submit final plans by September 6, 2018. Further, state progress reports were also required by the CPP on September 6, 2017. The final rule was published in the Federal Register on October 23, 2015.

In addition, on October 23, 2015, the EPA published a proposed Federal Plan and proposed model trading rules for both Intensity-Based and Mass-Based programs that the EPA will implement in states that fail to submit plans. The EPA was expected to finalize the FIP and model trading rules by summer 2016. The impact of the Supreme Court stay of the CPP on the EPA's finalization of these proposed rules, the State Plan submittal deadlines and the interim and final CPP compliance deadlines is uncertain at this time.

In the final CPP rule, an affected source is any fossil fuel-fired electric steam generating unit (e.g., utility boiler, integrated-gasification combined-cycle ("IGCC")), or NGCC that was in operation or under construction as of January 8, 2014. Simple-cycle CTs are excluded from the definition of affected units. Therefore, all Company owned fossil steam and NGCC units are considered affected units up through and including the Brunswick Power Station, which has commenced operations in 2016.

The final rule requires each state with affected EGUs to develop and implement plans that ensure that the affected EGUs in their states either individually, together, or in combination with other measures to achieve the interim and final Intensity-Based targets or Mass-Based targets. As identified in Chapter 1, each state with affected EGUs will have six options for compliance under the CPP. Three options are Intensity-Based and three options are Mass-Based. The three Intensity-Based options are:

- Intensity-Based Dual Rate Program – An Intensity-Based CO_2 program that requires each existing:
    - steam unit to achieve an intensity target of 1,305 lbs of CO_2 per MWh by 2030, and beyond; and
    - NGCC units to achieve intensity targets of 771 lbs of CO_2 per MWh by 2030, and beyond.

These standards are consistent for any state that elects an Intensity-Based Dual Rate Program;

- Intensity-Based State Average Program – An Intensity-Based CO_2 program that requires all affected existing generation units to achieve a portfolio average intensity target by 2030, and beyond. In Virginia that average intensity is 934 lbs of CO_2 per MWh by 2030 and beyond. The 2030 and beyond targets for West Virginia and North Carolina are 1,305 lbs of CO_2 per MWh and 1,136 lbs of CO_2 per MWh, respectively; and
- Unique State Intensity-Based Program – A unique state Intensity-Based program designed so that the ultimate state level intensity target does not exceed those targets described in the Intensity-Based targets set forth in 1 and 2 above.

The three options that are Mass-Based are:

- Mass-Based Emissions Cap (existing units only) Program – A Mass-Based program that limits the total CO_2 emissions from the existing fleet of affected generating units. In Virginia, this limit is 27,433,111 short tons CO_2 (per year) beginning in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,325,342 short tons of CO_2 and 51,266,234 short tons of CO_2, respectively;
- Mass-Based Emissions Cap (existing and new units) Program – A Mass-Based program that limits the total CO_2 emissions from both the existing fleet of generating units and all new generation units in the future. In Virginia, this limit is 27,830,174 short tons of CO_2 (per year) beginning in 2030 and beyond. The corresponding limits for West Virginia and North Carolina, in 2030 and beyond, are 51,857,307 short tons of CO_2 and 51,876,856 short tons of CO_2, respectively; and
- Unique State Mass-Based Program – A unique state Mass-Based approach.

Intensity-Based Programs

Under each of the Intensity-Based options, states can design plans to encourage EGUs to reduce CO_2 emissions through actions such as heat rate improvements, fuel switching, environmental dispatch, retirements, or a state may implement an intra-state trading program to enable EGUs to generate and/or procure ERCs. ERCs are measured in MWhs and can be generated by: (i) affected units operating below the performance standard; (ii) generation of zero emitting energy (including new nuclear generation); and (iii) demand-side and supply-side energy efficiency. To demonstrate compliance, an affected EGU (or portfolio of affected EGUs) operating above the emissions performance rate would procure (or generate) ERCs and add those ERCs to the denominator in its rate calculation resulting in a lower calculated rate. For example, assume that an affected NGCC operating at 1,000 lbs CO_2/MWh and needs to comply with a target rate of 771 lbs CO_2/MWh. To achieve compliance, the NGCC needs to procure the following amount of ERCs for each MWh that the NGCC generates in a given compliance period:

$$(1{,}000 \text{ lbs } CO_2 \text{ per MWh} \div 771 \text{ lbs. } CO_2 \text{ per MWh}) - 1 = 0.297 \text{ ERCs}$$

In states that adopt an Intensity-Based Dual Rate Program, ERCs can also be generated by affected NGCC units following an EPA formula that encourages efficient gas generation. These ERCs, called

Gas-Shift ERCs, are available for compliance use by fossil steam generating (coal, gas, and oil) units only. This is a valuable option for the Company and its customers given that the Company currently has a fuel diverse fleet of generation assets that includes many large NGCCs. For example, affected Company owned NGCC generation units could produce Gas-Shift ERCs that could then be used by the Company to help meet the compliance obligations of the Company's coal fleet or other steam units located within the state.

The role of ERCs in Intensity-Based CPP compliance is significant. In addition to the Gas-Shift ERCs described above, the amount of ERCs that may be available to the Company and its customers corresponds to the amount of renewable generation available to the Company. This includes self-build renewable generation, along with renewable generation purchases from within the state or potentially outside the state. ERCs can also be earned by the amount of new nuclear generation including uprates to existing nuclear facilities. This ERC supply aspect should be compared to Mass-Based programs that have hard limits on the level of CO_2 that may be emitted in a given time period. Given the societal and industry movement towards renewable energy, it is not unrealistic to anticipate that the level of renewable generation will increase over time thus increasing the available supply of ERCs. Conversely, under provisions of the CPP, the supply of CO_2 allowances under Mass-Based programs will stay fixed even though load increases. This expected supply dynamic increases the options available to the Company and its customers under an Intensity-Based program which will help keep rates low, and help maintain a level of fuel price mitigation for the Company's customers via fuel diversity.

Mass-Based Programs

Mass-Based programs are designed to collectively cap total CO_2 emissions from all affected EGUs during any given compliance period. For each ton of CO_2 emitted, the emitting entity must surrender a CO_2 allowance. These allowances could be directly allocated to affected facilities or other entities or can be auctioned (for sale) by a state. The Company strongly discourages the concept of auctioning allowances in the Commonwealth of Virginia because of the significant adverse impact to electric rates. This action could prove to be punitive to the Company's customers in that those customers would have to pay for both new generation units designed to meet the CPP and CO_2 allowances required to operate existing affected generation units.

Under a Mass-Based program that would allocate allowances, states can also hold back a selected level of CO_2 allowances, known as set-aside allowances. States can use these set-aside allowances as a mechanism to create incentives for the development of non-emitting resources (including new nuclear), DSM/energy efficiency ("EE") programs, or other clean energy options. An important point to stress is that set-aside allowances are not newly created allowances that add to the total supply of allowances. Rather, set-aside allowances are subtracted from the total allowance supply for any given state. This translates into fewer allowances available to affected EGUs and unpredictable market valuation of allowances.

Mass-Based programs must also account for an EPA concept called "leakage." The CPP defines leakage as emissions that would not otherwise occur, but result from the shift in generation from existing affected fossil generation to new fossil generation units that are considered regulated in accordance with Section 111(b) of the Clean Air Act and are not subject to the CPP. Under the current CPP model trading rules, a state implementing a Mass-Based compliance program can choose one of three options to address such leakage. Those options are:

- Include existing affected generation units and new generation units in the Mass-Based program: As stated in Chapter 1 and as shown in Chapter 6, this option would be difficult to achieve and costly for Virginia given its generation capacity position coupled with Virginia's expected electric energy demand growth. Chapter 6 includes Plan E: Mass Emission Cap (existing and new units) that identifies an expansion plan that would be necessary in order to meet the CO_2 emission standards for Virginia. Not only is this Plan the most costly of the Plans evaluated in the 2016 Plan filing, it would require the Company to retire its entire coal generation fleet in Virginia, including VCHEC in 2029. This would likely cause significant economic harm to Virginia and also substantially reduce the fuel diversity within the Company's generation fleet leaving customers vulnerable to natural gas market price volatility;
- Use an allowance allocation method that counteracts leakage: Under the current CPP model trading rules, the state must populate a set-aside portion of allowances to existing affected NGCC units to encourage NGCC generation over steam generation and when a unit retires those allocated allowances must be transferred to the renewable set-aside allowance portion. The theory behind this approach is that it will establish an incentive for operation of existing affected NGCC units in lieu of new NGCC generation not subject to the CPP, but still regulated under the EPA's New Source Performance Standards ("NSPS") under CAA Section 111(b), and will financially incent new renewable to get built. Again, these set-aside allowances will be subtracted from the overall CO_2 allowance supply; or
- A unique method that demonstrates to the EPA that leakage is not likely to occur.

Interstate Trading and Banking of ERCs and CO_2 Allowances

Overall, the Company favors CPP programs that promote trading of ERCs and/or CO_2 allowances. This is a key aspect of any program because trading provides a clear market price signal which is the most efficient means of emission mitigation. Also, trading markets offer flexibility in the event of years where a higher level of ERCs or CO_2 allowances are required due to higher than expected fossil generation resulting from weather, or outages of low- or non-emitting generation resources, or both. Through the CPP and the associated model trading rules, the EPA has offered a framework that defines "trading-ready" programs. In other words, programs that will likely be approved by EPA and eligible to conduct interstate exchange of ERCs or CO_2 allowances with other trading-ready states. Given that the definition of "trading-ready" programs has already been established by the EPA, it is highly likely that most states will adopt this framework rather than seeking approval of a program that runs the risk of either being rejected by the EPA, or approved as a unique program that has no other like programs with which to trade. Therefore, the Company expects that "trading-ready" programs offered in the CPP and the associated EPA model rule will be adopted by most states and offer the best alternative to promote robust and liquid trading markets.

The 2015 Plan Final Order required the Company to examine the cost benefits of trading emission allowances or emission rate credits, or acquiring renewable resources from inside or outside of Virginia. As stated above, the ability to trade CO_2 allowances or ERCs, or acquire renewable generation offers clear price signals that enable more accurate economic decisions but most importantly, offers the Company and its customers flexibility in compliance with the CPP. This flexibility (or optionality) is difficult to quantify at this time in an inherently static cost benefit analysis especially since these markets have yet to develop. Once markets have developed, however, the Company will utilize these markets in making operational, tactical or strategic generation portfolio decisions to assure reliable electric service to customers at the lowest reasonable cost. Nevertheless, utilizing the information included in this 2016 Plan, the Company's high level estimate of the value of trading CO_2 allowances or ERCs is estimated to range between $0 and $25 million per year. This range could be even greater if the price of CO_2 allowances or ERCs is higher than forecasted by ICF and used in this 2016 Plan.

In general, states that adopt the standard Mass-Based programs can trade CO_2 allowances with other states that have adopted Mass-Based programs. Under the CPP, the EPA considers Mass-Based programs to be "trading ready." This, however, is not the case with Intensity-Based programs. EPA maintains that states that adopt an Intensity-Based program may trade ERCs with other states that have "similar" Intensity-Based programs. The final assessment of what state programs are "similar" is the responsibility of the EPA and standards for such determination are uncertain with one exception. That exception is for states adopting a Dual Rate program consistent with the EPA's proposed model rule. Dual rate programs that are consistent with the Intensity-Based model rule are considered by the EPA to be "trading ready." The Company maintains that for states that elect to pursue Intensity-Based programs, it is likely that those states will elect the Intensity-Based Dual Rate Program option in order to mitigate the uncertainty associated with meeting the "similarity" standard mentioned above. Given this likely outcome coupled with the advantages of an Intensity-Based program mentioned above, and given the Company's understanding of the EPA model trading rules as currently proposed, the Company believes that the adoption of an Intensity-Based Dual Rate approach offers the most cost-effective and flexible option for implementing the CPP in the Commonwealth of Virginia.

Regarding banking, the CPP allows for un-constrained banking of ERCs and/or CO_2 allowances. In other words there is no expiration period associated with banked ERCs and/or CO_2 allowances.

Early Action/Clean Energy Incentive Program

Within the CPP, the EPA has included a program entitled the Clean Energy Incentive Program ("CEIP"). The CEIP is designed to provide incentives for early development of new renewable generation and DSM/EE programs before the start of the CPP's mandatory reductions period in 2022. More specifically, projects that fit these categories must start construction (in the case of renewable generation), or commence operation (in the case of DSM/EE) after the final State Plan is submitted. Further, credits will be awarded to eligible projects for energy (MWhs) they either generate (renewables) or save (reduce demand) in low-income communities (for DSM/EE) during 2020 or 2021.

Under the CEIP, the state will issue early action ERCs (in an Intensity-Based program) or allowances (in a Mass-Based program) and EPA will award matching ERCs or allowances from a nationwide pool totaling 300 million tons of CO_2. Approximately 4 million tons have been set aside for Virginia. Eligible renewable projects will be awarded CEIP credits on a 1:1 basis (for every 2 MWh generated, the state will issue 1 early action ERC (or allowance) to the project and EPA will issue a matching

credit (ERC or allowance)). Energy efficiency projects will be granted CEIP credits on a 2:1 basis (for every 2 MWh, the state will issue 2 credits and the EPA will issue a matching 2 credits).
To participate in the CEIP, the EPA is requiring states to implement offsetting adjustments to electric generating unit obligations imposed during the interim (2022 - 2029) period in an amount equivalent to the credits issued by the state under the CEIP. The offsetting requirement does not apply to the matching EPA credits.

The preamble to the final rule explains that a state with a Mass-Based program can satisfy the offsetting requirement by setting aside a portion of its interim period allowance budget and use that set-aside pool for purposes of awarding CEIP allowance credits. For Intensity-Based programs, the EPA asserts that a state could adjust the stringency of the emission rate targets during the interim compliance period to account for the issuance of CEIP ERCs or could retire an amount of ERCs during the interim compliance period that is equivalent to the amount of CEIP ERCs granted.

Although the CPP is final, the EPA has not yet finalized the specific provisions of the CEIP. Given the Supreme Court stay of the CPP, final details of the design, implementation and timelines related to the CEIP remain uncertain at this time.

Under the proposed provisions of the CEIP, a portion of the 400 MW of Virginia utility-scale solar generation the Company intends to phase in from 2016 - 2020 should be eligible for incentives. The Company does not anticipate any ERCs or allowances to be granted under the CEIP from its current set of approved low-income programs in Virginia because the program was approved for a three year period in 2015. The Company would have to seek approval of additional low-income programs that may allow for additional participation beyond the approval dates. However, as of the 2016 Plan cycle, the Company has not developed or analyzed any new low-income programs during the CEIP window identified in the CPP.

3.1.4 GENERATION RETIREMENTS/BLACKSTART

Retirements

Based on the current and anticipated environmental regulations along with current market conditions, the 2016 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. Yorktown Units 1 (159 MW) and 2 (164 MW) are scheduled for retirement in 2017. On April 16, 2016, the EPA granted permission through an Administrative Order to operate the Yorktown coal-fired units through April 15, 2017 under certain limitations consistent with the federal Mercury and Air Toxics Standards ("MATS") rule.

Currently under evaluation is the potential retirement of Yorktown Unit 3, 790 MW of oil-fired generation, to be retired by 2022 (included in all CPP-Compliant Alternative Plans). Also under evaluation are the retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW), and Mecklenburg Units 1 (69 MW) and 2 (69 MW), all modeled for retirement by 2022 (Plans B, C, D, and E). Plan E: Mass Emissions Cap (existing and new units) models the potential retirement of the entire Company-owned Virginia coal fleet, including all coal generation in Virginia by 2022, except for VCHEC, which retires by 2029. Appendix 3J lists the planned retirements included in Plan B: Intensity Dual Rate.

Blackstart

Blackstart generators are generating units that are able to start without an outside electrical supply or are able to remain operating at reduced levels when automatically disconnected from the grid. The North American Electric Reliability Corporation ("NERC") Reliability Standard EOP-005 requires the RTO to have a plan that allows for restoring its system following a complete shutdown (i.e., blackout). As the RTO, PJM performs an analysis to verify all requirements are met and coordinates this analysis with the Company in its role as the Transmission Owner. The Company and other PJM members have and continue to work with PJM to implement a RTO-wide strategy for procuring blackstart resources. This strategy ensures a resilient and robust ability to meet blackstart and restoration requirements. It is described in detail in Section 10 of PJM Manual 14D – Generator Operational Requirements. PJM will issue an RTO-wide Request for Proposals ("RFP") for blackstart generation every five years, which will be open to all existing and potential new blackstart units on a voluntary basis. Resources are selected based upon the individual needs of each transmission zone. The first five-year selection process was initiated in 2013 and resulted in blackstart solutions totaling 286 MW in the DOM Zone. Two solutions became effective on June 1, 2015. The first was for 50 MW and the second was for 85 MW; and another solution (151 MW) is scheduled for final acceptance on June 30, 2016. Blackstart solutions from the subsequent five-year selection processes will be effective on the following April 1. For incremental changes in resource needs or availability that may arise between the five-year solicitations, the strategy includes an incremental RFP process.

3.1.5 GENERATION UNDER CONSTRUCTION

Pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly (House Bill 1686), the SCC granted the Company in November 2012 a "blanket" certificate of public convenience and necessity ("CPCN") to construct and operate up to 24 MW alternating current ("AC") (30 MW DC) of Company-owned solar DG facilities at selected large commercial and industrial customer locations dispersed throughout its Virginia service territory by 2016 (SPP). To date, the Company has installed 2 MW (nameplate) of new solar generation at various customer locations throughout its service territory. Approximately 7 MW (nameplate) of new solar under the SPP are at various stages of development.

The Company's Greensville Power Station (1,585 MW CC unit) CPCN was approved by the SCC on March 29, 2016. It is expected to be online by 2019.

Figure 3.1.5.1 and Appendix 3K provide a summary of the generation under construction along with the forecasted in-service date and summer/winter capacity.

Figure 3.1.5.1 - Generation under Construction

Forecasted COD[1]	Unit Name	Location	Primary Fuel	Unit Type	Capacity (Net MW) Nameplate	Summer	Winter
2017	Solar Partnership Program	VA	Solar	Intermittent	7	2	2
2019	Greensville County Power Station	VA	Natural Gas	Intermediate/Baseload	1,585	1,585	1,710

Note: 1) Commercial Operation Date.

3.1.6 NON-UTILITY GENERATION

A portion of the Company's load and energy requirements is supplemented with contracted NUG units and market purchases. The Company has existing contracts with fossil-burning and renewable NUGs for capacity of 1,277 MW. These NUGs are considered firm generating capacity resources and are included in the 2016 Plan.

Each of the NUG facilities listed as a capacity resource in Appendix 3B, including the solar NUGs, is under contract to supply capacity and energy to the Company. NUG units are obligated to provide firm generating capacity and energy at the contracted terms during the life of the contract. The firm generating capacity from NUGs is included as a resource in meeting the reserve requirements.

For modeling purposes, the Company assumed that its NUG capacity will be available as a firm generating capacity resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned/sponsored supply- or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

Additionally, the Company is currently working with a number of potential solar qualifying facilities. The Short-Term Action Plan and all of the CPP-Compliant Alternative Plans include a total of 600 MW (nameplate) of North Carolina solar NUGs by 2017, which includes 308 MW of PPAs that have been signed as of May 2015. The Company is continually evaluating NUG opportunities as they arise to determine if they are beneficial to customers.

3.1.7 WHOLESALE & PURCHASED POWER

Wholesale Power Sales

The Company currently provides full requirements wholesale power sales to three entities, which are included in the Company's load forecast. These entities are Craig Botetourt Electric Cooperative, the Virginia Municipal Electric Association No.1, and the Town of Windsor in North Carolina. Additionally, the Company has partial requirements contracts to supply the supplemental power needs of the North Carolina Electric Membership Cooperative. Appendix 3L provides a listing of wholesale power sales contracts with parties whom the Company has either committed, or expects to sell power during the Planning Period.

Purchased Power

Except for the NUG contracts discussed in Section 3.1.6, the Company does not have any bilateral contractual obligations with wholesale power suppliers or power marketers. As a member of PJM, the Company has the option to buy capacity through the Reliability Pricing Model ("RPM") auction ("RPM auction") process to satisfy its RPM requirements. The Company has procured its capacity obligation from the RPM market through May 31, 2019. The method chosen by neighboring states to meet EPA's proposed CPP targets in their respective states could adversely affect the future price and/or availability of purchased power should a large number of steam generation units (i.e., coal and oil) elect to retire.

Behind-the-Meter Generation

BTMG occurs on the customer's side of the meter. The Company purchases all output from the customer and services all of the customer's capacity and energy requirements. The unit descriptions are provided in Appendix 3B.

3.1.8 REQUEST FOR PROPOSAL

The Company issued an RFP on November 3, 2014, for up to approximately 1,600 MW of new or existing intermediate or baseload dispatchable generation located within the DOM Zone, or designated areas within an adjacent zone of PJM. The RFP requested PPAs with a term of 10 to 20 years, commencing in the 2019/2020 timeframe. Multiple proposals were received and evaluated. The Company's self-build CC in Greensville County provided superior customer benefits compared to all other options. The Greensville County CPCN was approved by the SCC on March 29, 2016.

The Company issued an RFP on July 22, 2015 seeking third party bids for solar facilities between 1 and 20 MW of capacity that are scheduled to be on-line by 2017. The proposals could be for either PPAs for 1 to 20 MW, or for the purchase of development projects between 10 and 20 MW. The Company also would have considered proposals for greater than 20 MW if the bidder could demonstrate the ability to complete the PJM interconnection process on schedule to meet the 2016-2017 in service date. Multiple proposals were received and evaluated. As a result of the RFP, the Company signed 2 PPAs for 40 MW and chose the Scott Solar development project along with two Company self-builds at Whitehouse and Woodland.

3.2 DEMAND-SIDE RESOURCES

The Commonwealth of Virginia has a public policy goal set forth in the 2007 Electric Utility Reregulation Act of reducing the consumption of electric energy by retail customers by 2022 by an amount equal to 10% of the amount of electric energy consumed by retail customers in Virginia in 2006. The Company has expressed its commitment to helping Virginia reach this goal through bringing applications for the approval of cost-effective DSM programs to the SCC. Related to and consistent with the goal, DSM programs are an important part of the Company's portfolio available to meet customers' growing need for electricity along with supply-side resources.

The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. Demand-side resources encourage the more efficient use of existing resources and delay or eliminate the need for new supply-side infrastructure. The Company's DSM programs are designed to provide customers the opportunity to manage or reduce their electricity usage.

In this 2016 Plan, four categories of DSM programs are addressed: i) those approved by the SCC and NCUC; ii) those filed with the SCC for approval, iii) those programs that are under consideration but have not been evaluated and may be potential DSM resources; and iv) those programs currently rejected from further consideration at this time. The Company's Programs have been designed and evaluated using a system-level analysis. For reference purposes, Figure 3.2.1 provides a graphical representation of the approved, proposed, future, and rejected programs described in Chapters 3 and 5.

Figure 3.2.1 - DSM Tariffs & Programs

<table>
<tr><th>Tariff</th><th>Status (VA/NC)</th></tr>
<tr><td>Standby Generator Tariff</td><td rowspan="2">Approved/Approved</td></tr>
<tr><td>Curtailable Service Tariff</td></tr>
<tr><th>Program</th><th>Status (VA/NC)</th></tr>
<tr><td>Air Conditioner Cycling Program</td><td>Approved/Approved</td></tr>
<tr><td>Residential Low Income Program</td><td rowspan="2">Completed/Completed</td></tr>
<tr><td>Residential Lighting Program</td></tr>
<tr><td>Commercial Lighting Program</td><td rowspan="2">Closed/Closed</td></tr>
<tr><td>Commercial HVAC Upgrade</td></tr>
<tr><td>Non-Residential Distributed Generation Program</td><td>Approved/Rejected</td></tr>
<tr><td>Non-Residential Energy Audit Program</td><td rowspan="12">Approved/Approved</td></tr>
<tr><td>Non-Residential Duct Testing and Sealing Program</td></tr>
<tr><td>Residential Bundle Program</td></tr>
<tr><td>   Residential Home Energy Check-Up Program</td></tr>
<tr><td>   Residential Duct Sealing Program</td></tr>
<tr><td>   Residential Heat Pump Tune Up Program</td></tr>
<tr><td>   Residential Heat Pump Upgrade Program</td></tr>
<tr><td>Non-Residential Window Film Program</td></tr>
<tr><td>Non-Residential Lighting Systems & Controls Program</td></tr>
<tr><td>Non-Residential Heating and Cooling Efficiency Program</td></tr>
<tr><td>Income and Age Qualifying Home Improvement Program</td></tr>
<tr><td>Residential Appliance Recycling Program</td><td>Approved/No Plans</td></tr>
<tr><td>Residential Programmable Thermostat Program</td><td>Rejected/No Plans</td></tr>
<tr><td>Small Business Improvement Program</td><td>Approved/Under Evaluation</td></tr>
<tr><td>Home Energy Assessment</td><td rowspan="3">Under Consideration/
Under Consideration</td></tr>
<tr><td>Prescriptive Program for Non-Residential Customers</td></tr>
<tr><td>Voltage Conservation</td></tr>
<tr><td>Non-Residential HVAC Tune-Up Program</td><td rowspan="25">Rejected and Currently Not Under Consideration</td></tr>
<tr><td>Energy Management System Program</td></tr>
<tr><td>ENERGY STAR® New Homes Program</td></tr>
<tr><td>Geo-Thermal Heat Pump Program</td></tr>
<tr><td>Home Energy Comparison Program</td></tr>
<tr><td>Home Performance with ENERGY STAR® Program</td></tr>
<tr><td>In-Home Energy Display Program</td></tr>
<tr><td>Premium Efficiency Motors Program</td></tr>
<tr><td>Programmable Thermostat Program</td></tr>
<tr><td>Residential Refrigerator Turn-In Program</td></tr>
<tr><td>Residential Solar Water Heating Program</td></tr>
<tr><td>Residential Water Heater Cycling Program</td></tr>
<tr><td>Residential Comprehensive Energy Audit Program</td></tr>
<tr><td>Residential Radiant Barrier Program</td></tr>
<tr><td>Residential Lighting (Phase II) Program</td></tr>
<tr><td>Non-Residential Refrigeration Program</td></tr>
<tr><td>Cool Roof Program</td></tr>
<tr><td>Non-Residential Data Centers Program</td></tr>
<tr><td>Non-Residential Re-commissioning</td></tr>
<tr><td>Non-Residential Curtailable Service Program</td></tr>
<tr><td>Non-Residential Custom Incentive</td></tr>
<tr><td>Enhanced Air Conditioner Direct Load Control Program</td></tr>
<tr><td>Residential Controllable Thermostat Program</td></tr>
<tr><td>Residential Retail LED Lighting Program</td></tr>
<tr><td>Residential New Homes Program</td></tr>
</table>

3.2.1 DSM PROGRAM DEFINITIONS

For purposes of its DSM programs in Virginia, the Company applies the Virginia definitions set forth in Va. Code § 56-576, as provided below.

- **Demand Response** – Measures aimed at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.
- **Energy Efficiency Program** – A program that reduces the total amount of electricity that is required for the same process or activity implemented after the expiration of capped rates. Energy efficiency programs include equipment, physical, or program change designed to produce measured and verified reductions in the amount of electricity required to perform the same function and produce the same or a similar outcome. Energy efficiency programs may include, but are not limited to, i) programs that result in improvements in lighting design, heating, ventilation, and air conditioning systems, appliances, building envelopes, and industrial and commercial processes; ii) measures, such as, but not limited to, the installation of advanced meters, implemented or installed by utilities, that reduce fuel use or losses of electricity and otherwise improve internal operating efficiency in generation, transmission, and distribution systems; and (iii) customer engagement programs that result in measurable and verifiable energy savings that lead to efficient use patterns and practices. Energy efficiency programs include demand response, combined heat and power and waste heat recovery, curtailment, or other programs that are designed to reduce electricity consumption, so long as they reduce the total amount of electricity that is required for the same process or activity. Utilities are authorized to install and operate such advanced metering technology and equipment on a customer's premises; however, nothing in Chapter 23 of Title 56 establishes a requirement that an energy efficiency program be implemented on a customer's premises and be connected to a customer's wiring on the customer's side of the inter-connection without the customer's expressed consent.
- **Peak-Shaving** – Measures aimed solely at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid.

For purposes of its DSM programs in North Carolina, the Company applies the definitions set forth in NCGS § 62-133.8 (a) (2) and (4) for DSM and energy efficiency measures as defined below.

- **Demand-Side Management**: Activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to non-peak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.
- **Energy Efficiency Measure**: Equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. Energy efficiency measure includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. It does not include DSM.

3.2.2 CURRENT DSM TARIFFS

The Company modeled existing DSM pricing tariffs over the Study Period, based on historical data from the Company's Customer Information System ("CIS"). These projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future. No active DSM pricing tariffs have been discontinued since the Company's 2015 Plan.

STANDBY GENERATION

Program Type: Energy Efficiency - Demand Response

Target Class: Commercial & Industrial

Participants: 5 customers on Standby Generation in Virginia

Capacity Available: See Figure 3.2.2.1

The Company currently offers one DSM pricing tariff, the Standby Generation ("SG") rate schedule, in Virginia. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed.

The SG rate schedule provides a direct means of implementing load reduction during peak periods by transferring load normally served by the Company to a customer's standby generator. The customer receives a bill credit based on a contracted capacity level or average capacity generated during a billing month when SG is requested.

During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator. Figure 3.2.2.1 below provides estimated load response data for summer/winter 2015. Additional jurisdictional rate schedule information is available on the Company's website at www.dom.com.

Figure 3.2.2.1 - Estimated Load Response Data

Tariff	Summer 2015		Winter 2015	
	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	16	2	12	2

3.2.3 CURRENT & COMPLETED DSM PILOTS & DEMONSTRATIONS

Pilots

The SCC approved nine pilot DSM programs in Case No. PUE-2007-00089, all of which have ended. The Company has received SCC approval for implementation of additional pilots and they are described below.

Dynamic Pricing Tariffs Pilot

State:	Virginia
Target Class:	Residential and Non-Residential
Pilot Type:	Peak-Shaving
Pilot Duration:	Enrollment closed on November 30, 2014 Pilot concludes July 31, 2017

Description:

On September 30, 2010, the Company filed an application with the SCC (Case No. PUE-2010-00135) proposing to offer three experimental and voluntary dynamic pricing tariffs to prepare for a potential system-wide offering in the future. The filing was in response to the SCC's directive to the Company to establish a pilot program under which eligible customers volunteering to participate would be provided the ability to purchase electricity from the Company at dynamic rates.

A dynamic pricing schedule allows the Company to apply different prices as system production costs change. The basic premise is that if customers are willing to modify behavior and use less electricity during high price periods, they will have the opportunity to save money, and the Company in turn will be able to reduce the amount of energy it would otherwise have to generate or purchase during peak periods.

Specifically, the Pilot is limited to 3,000 participants consisting of up to 2,000 residential customers taking service under experimental dynamic pricing tariff DP-R and 1,000 commercial/general customers taking service under dynamic pricing tariffs DP-1 and DP-2. Participation in the pilot requires either an AMI meter or an existing Interval Data Recorder ("IDR") meter at the customer location. The meter records energy usage every 30 minutes, which enables the Company to offer pricing that varies based on the time of day. In addition, the pricing varies based on the season, the classification for the day, and the customer's demand. Therefore, the AMI or IDR meter coupled with the dynamic pricing schedules allows customers to manage their energy costs based on the time of day. Additional information regarding the Pilot is available at http://www.dom.com/smartprice.

Status:

The Dynamic Pricing Pilot program was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011. On July 31, 2015, the Company filed a Motion to Extend the Pilot, which was approved December 18, 2015. The Pilot is scheduled to end on July 31, 2017. The Company launched this Pilot program on July 1, 2011. As of December 2015, there were 569 customers taking service under the residential DP-R tariff; 61 customers taking service under the commercial DP-1 tariff; and 76 customers taking service under the commercial DP-2 tariff.