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May 1, 2018

Joel H. Peck, Clerk
Virginia State Corporation Commission
C/o Document Control Center
1300 East Main Street
Richmond, VA 23219

RE: Case No. PUR-2018-00065

Dear Mr. Peck:

Virginia Electric and Power Company ("Dominion Energy Virginia" or the "Company") is pleased to submit to the Virginia State Corporation Commission ("Commission") its 2018 Integrated Resource Plan (the "2018 Plan" or "the Plan") for the 15-year planning period of 2019 through 2033. The Plan is submitted in accordance with § 56-599 of the Code of Virginia. Simultaneously, the Plan is being filed in North Carolina with the North Carolina Utilities Commission ("NCUC") in accordance with § 62.2 of the North Carolina General Statutes and Rule R8-60 of the Rules and Regulations of the NCUC.

The 2018 Plan reflects the Company's belief that regulation of power station carbon dioxide ("CO_2") emissions is virtually assured in the future, either through new federal initiatives or through measures adopted at the state level. Although federal executive and judicial actions have halted implementation of the U.S. Environmental Protection Agency's Clean Power Plan ("CPP"), the Commonwealth of Virginia has attempted to address carbon emissions through regulatory action. Specifically, the Virginia Department of Environmental Quality ("DEQ") has released a draft proposal capping CO_2 emissions from the state's electric generating units ("EGUs"). The draft proposes linking a cap-and-trade program in Virginia with the existing Regional Greenhouse Gas Initiative ("RGGI") now being implemented in the northeastern United States. Regardless of the precise mechanism of carbon control, the Company is committed to reducing greenhouse gas emissions.

Because of the uncertainty regarding the final form and scope of carbon emission regulations, the 2018 Plan presents no recommended long-term path for meeting the long-term energy needs of the Company's customers. Instead, the 2018 Plan presents a range of options (the "Alternative Plans") representing plausible future paths for meeting the electric needs of Dominion Energy Virginia customers. The Company also offers a strategic plan for the next five years in its Short-Term Action Plan.

The Plan Reflects the Transition to a Lower Emissions Rate Future

The Company has been a leader in reducing carbon emissions, having begun its transition to a generating fleet with lower carbon intensity well before the proposed federal and state carbon regulations considered in the 2018 Plan. Between 2000 and 2017, the carbon intensity of the Company's units serving Virginia declined by 35 percent while power production by these units increased by 14 percent. As the 2018 Plan reflects, Dominion Energy Virginia will continue moving toward cleaner, more efficient, and lower-emitting ways of generating, delivering, storing, and transporting energy.

Renewable resources are becoming a more cost-effective means of meeting the growing energy demands of customers. This is particularly true of solar power. The continuing development of solar photovoltaic ("PV") technology has made this type of generation cost-competitive with other, more traditional forms of generation. Backed up by units using low-emitting natural gas, renewable resources will play an increasingly important role in the Company's generation fleet serving customers in Virginia and North Carolina. In fact, all of the Alternative Plans presented in the 2018 Plan call for the potential development of 4,720 megawatts ("MW") of additional solar capacity by 2033. By 2043, four of the Alternative Plans would expand the Dominion Energy Virginia solar fleet by 7,200 MW.

The Virginia General Assembly affirmed the growing importance of renewable energy generation in passing the Grid Transformation and Security Act of 2018 (the "GTSA"), which was signed into law by Governor Ralph Northam on March 9, 2018. The new law finds that up to an additional 5,000 MW of utility-scale electric generating facilities powered by solar and wind energy is in the public interest, along with up to an additional 500 MW of non-utility scale solar or wind generating facilities, including rooftop solar installations. The GTSA also encourages electric distribution grid transformation projects, in part to facilitate the integration of renewable generation resources into the Company's system. The Company includes discussion of its plans to comply with the GTSA's various mandates as part of its Short-Term Action Plan contained in this 2018 Plan.

While acknowledging the rapidly increasing role of renewable resources, the 2018 Plan continues the longstanding integrated resource planning ("IRP") goal of identifying an economical blend of resources capable of meeting the future energy needs of the Company's customers under a variety of scenarios. The Plan recognizes the continued importance of lower-emission natural gas as a significant source of electric generation, with all five of the Alternative Plans including potential development of 3,664 MW of additional combustion turbine ("CT") capacity by 2033.

The 2018 Plan also recognizes that nuclear power must continue to play a major role in power generation in a lower-carbon, lower-emission future. Therefore, all of the Alternative Plans assume that all of the Company's nuclear generation in Virginia, which includes two reactors at Surry Power Station and two at North Anna Power Station, will receive 20-year operating license extensions from the U.S. Nuclear Regulatory Commission. Relicensing the units will ensure that these reactors continue their zero-carbon production of electricity into the second half of the 21st century. The Surry and North Anna nuclear units continue to be by far the largest source of zero-emissions generation for the Company. Their operation avoids the release of approximately 22 million tons of CO_2 per year. More than 100,000 acres of solar PV facilities would be needed to match the nuclear units' annual power output.

In addition to new and relicensed generation, the Plan also evaluates demand-side management programs to help customers conserve energy or reduce system peak loads. All of the Alternative Plans call for implementation of demand-side programs capable of reducing customers' overall annual energy usage by 805 gigawatt-hours (GWh) and system peak demand by 304 MW by 2033. The 2018 Plan does not yet reflect the emphasis placed on energy conservation by the GTSA. The GTSA requires the Company to propose energy efficiency programs with projected costs of at least $870 million for the period beginning

July 1, 2018, and ending July 1, 2028, including its existing approved energy efficiency programs. With the GTSA becoming law on July 1, 2018, the Company anticipates directly addressing this expansion of proposed energy conservation programming in future filings with the Commission.

Alternative Plans Examined by the Company

While uncertainty still surrounds future carbon regulations, the Company believes that the IRP process should continue with a thorough evaluation of options for complying with various regulatory alternatives. The Alternative Plans range from a scenario with no new future CO_2 regulation to various forms of state or federal carbon control initiatives. Dominion Energy Virginia does not present an Alternative Plan based on implementation of the CPP because the Company does not believe that future implementation of the CPP is plausible. Nevertheless, the Company provides analysis for a CPP-based plan in an appendix.

The five Alternative Plans presented in the 2018 Plan are:

Plan A: No CO_2 Tax. Plan A is based on a scenario of a future without any new regulation of or restrictions on power station carbon emissions. Plan A serves as a least-cost baseline for comparing the costs of the other plans.

Plan B: Virginia RGGI (Unlimited Imports). Plan B, the second Alternative Plan, assumes implementation of the DEQ's draft carbon reduction regulations published in the *Virginia Register* in January 2018. The draft proposal links Virginia to RGGI. Plan B assumes that the Company's compliance with this regulation is achieved largely through the use of more carbon intensive out-of-state energy and generating capacity.

Plan C: RGGI (Unlimited Imports). Plan C assumes Virginia will become a full member of RGGI. It also assumes that the Company's compliance with RGGI is met largely through the use of more carbon intensive out-of-state energy and capacity. The Company presents Plan C as a comparison against Plan B. Plan C reflects the higher cost of allowance purchases if Virginia becomes a full member of RGGI, with no offsetting payments as would occur under the DEQ's draft carbon regulations modeled in Plan B.

Plan D: RGGI (Limited Imports). Like Plan C, Plan D assumes Virginia will become a full member of RGGI. However, Plan D assumes the Company's compliance with RGGI will be achieved primarily through generation built in Virginia and limited imports of more carbon-intensive power. Like Plan C, Plan D reflects the higher cost of allowance purchases with no offsetting payments.

Plan E: Federal CO_2 Program. Plan E assumes that Virginia does not implement any CO_2 reduction program, but also assumes that federal CO_2 legislation is enacted imposing restrictions beginning in 2026.

As detailed in Chapter 3 of the 2018 Plan, modeling performed for the Company indicates that, if not mitigated by other public policies including the successful implementation of the renewable energy, energy efficiency and other provisions of the GTSA, Virginia's linkage to RGGI would encourage the import into the Commonwealth of power from out-of-state, higher carbon-intensity generating resources. This would occur through the Company's increased need to purchase out-of-state energy and capacity to meet its obligations to serve Virginia customers. It would also encourage customers able to shop competitively to purchase out-of-state power. At the same time, highly efficient and lower-emitting natural gas combined cycle facilities in Virginia would run less. While this would reduce carbon emissions in Virginia, the reductions would be offset by increased emissions elsewhere in the North American Electric Reliability Corporation ("NERC") Eastern Interconnect, which includes all of the PJM Interconnection and the RGGI region. Additionally, modeling indicates the higher level of power imports would increase the carbon footprint per Dominion Energy Virginia customer by 5.7 percent by 2030 and impose an additional $500 million in costs on Virginia customers from 2020 through 2030.

Common Elements of the Alternative Plans

Major common elements of the five alternatives within the planning period of 2019 through 2033 include:

- **Solar:** Development of 4,720 MW of solar PV generation by 2033.
- **Solar (Non-Utility Generators):** The addition of 760 MW of solar PV capacity owned by non-utility generators ("NUGs") under long-term contracts with the Company in Virginia and North Carolina by 2020.
- **Wind:** Construction and operation of the Coastal Virginia Offshore Wind demonstration project with a generating capacity of 12 MW by 2021. The project is to be located approximately 27 miles off the coast of Virginia Beach.
- **Nuclear:** Twenty-year operating license extensions for the four Company-owned nuclear units at the Surry and North Anna Power Stations. The Surry units would be relicensed by 2032 and 2033, and the North Anna units by 2038 and 2040.
- **Natural Gas:** Additional natural gas-fired generation, including completion of the 1,585 MW Greensville County Power Station using energy efficient, low-emission combined cycle technology, scheduled to begin service by 2019. All of the Alternative Plans also call for the addition of eight natural gas-powered facilities using CT technology with a combined capacity of approximately 3,664 MW by 2033.
- **Demand-Side Management:** Implementation of demand-side management programs, both already approved by or currently submitted to the Commission, capable of reducing overall annual customer energy usage by 805 GWh and system peak demand by 304 MW by 2033.
- **Potential Retirements (Fossil Fuels):** The potential retirement of 2,785 MW of generation powered by older, less efficient coal, oil, and natural gas technology by 2021 or 2022 at six Virginia sites. The Company announced earlier this year that 1,209 MW of this generation at five sites would be placed in cold reserve by December 2018. All generation retirements presented in the Alternative Plans should be considered tentative, with the Company's final decision being made at a future date after further analysis.
- **Potential Retirements (Biomass):** The potential retirement of 83 MW of biomass-powered generation using waste wood at Pittsylvania Power Station by 2021. The Pittsylvania facility is also scheduled to be placed in cold reserve in August 2018.

Additional Generation and Retirements in Alternative Plans

In addition to the common elements listed above, the various Alternative Plans contain additional resources and potential retirements by 2033, the end of the 15-year planning period.

- Plan A includes one additional CT facility with a total generating capacity of 458 MW.

- Plan B includes three additional CT facilities with a total capacity of 1,374 MW; two CT Aero-derivatives ("Aero") units with a capacity of approximately 238 MW; and an additional 1,920 MW of solar capacity.
- Plan C includes three additional CT plants totaling 1,374 MW; two CT Aero units generating 238 MW; and an additional 1,920 MW of solar capacity.
- Plan D calls for one natural gas-powered combined cycle facility using 2x1 technology of approximately 1,062 MW; one additional CT plant of approximately 458 MW; one CT Aero unit of approximately 119 MW; and an additional 1,920 MW of solar capacity.
- Plan E calls for an additional 1,280 MW of solar capacity.
- Finally, Plans B, C, and D include the potential retirement of 1,445 MW of additional coal units: Chesterfield Unit 5 (336 MW) and Unit 6 (670 MW) by 2023 and Clover Unit 1 (220 MW) and Unit 2 (219 MW) by 2025.

Under Plans B, C, D, and E, the Company's additional solar capacity would reach 7,200 MW at the end of the 25-year study period concluding in 2043. Under Plan A, the Company's additional solar capacity would reach 5,200 MW by the same year.

Cost and Rate Impact of Alternative Plans

All of the Alternative Plans envisioning compliance with state or federal carbon regulations would impose higher costs on customers, but the costs and rate impacts of the possible scenarios vary.

The net present value ("NPV") through 2043 of costs associated with the four plans including carbon regulation range from $1.54 billion to $4.04 billion greater than the NPV of the baseline plan (Plan A). Specifically, the incremental NPVs associated with each of the carbon-regulating alternatives are $1.54 billion (Plan B); $3.71 billion (Plan C); $4.04 billion (Plan D); and $3.09 billion (Plan E).

Additionally, modeling predicts that carbon regulation compliance would lead to higher bills for Dominion Energy Virginia's customers. By 2030, implementation of Plans B, C, D, or E would result in typical monthly residential bills (for 1,000 kilowatt-hours of usage) ranging from 2.2 percent (Plan E) to 5.6 percent (Plan D) higher than under the baseline plan (Plan A). Expressed in 2018 dollars, the additional monthly cost of electricity by 2030 for a typical residential customer would be $3.59 under Plan B, $5.01 under Plan C, $5.81 under Plan D, and $2.23 under Plan E.

Dominion Energy Virginia's Commitment

Dominion Energy Virginia remains committed to its longstanding goals of operating responsibly; maintaining a diverse, balanced generation fleet that avoids over-reliance on a single fuel type or technology; and providing reliable and affordable energy to its customers. These goals guided development of the 2018 Plan and will guide the Company in the future.

Sincerely,

Paul D. Koonce

Paul D. Koonce

Virginia Electric and Power Company's Report of Its Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

PUBLIC VERSION

Case No. PUR-2018-00065
Docket No. E-100, Sub 157

Filed: May 1, 2018

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APPENDIX

LIST OF ACRONYMS

Acronym	Meaning
2017 Plan	2017 Integrated Resource Plan
2018 Plan	2018 Integrated Resource Plan
AMI	Advanced Metering Infrastructure
AERO	Aero-derivative Generation
BTMG	Behind-the-Meter Generation
Btu	British Thermal Unit
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian
CC	Combined-Cycle
CCR	Cost Containment Reserve
CCS	Carbon Capture and Sequestration
CFB	Circulating Fluidized Bed
CFL	Compact Florescent Light
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Operating License
Company	Virginia Electric and Power Company
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
CVOW	Coastal Virginia Offshore Wind Project (formerly VOWTAP)
DC	Direct Current
DEQ	Virginia Department of Environmental Quality
DER	Distributed Energy Resource(s)
DG	Distributed Generation
DOE	U.S. Department of Energy
DOM LSE	Dominion Energy Load Serving Entity
DOM Zone	Dominion Energy Zone within the PJM Interconnection, L.L.C. Regional Transmission Organization
DSM	Demand-Side Management
EC	Enactment Clause
ECR	Emission Containment Reserve
ED-11	Executive Directive 11
EGU	Electric Generating Unit(s)
EI	Eastern Interconnect
EIA	U.S. Energy Information Administration
EM&V	Evaluation, Measurement, and Verification
EO-57	Executive Order 57
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GSP	Gross State Product
GTSA	Grid Transformation and Security Act of 2018
GWh	Gigawatt Hour(s)
Hg	Mercury
HVAC	Heating, Ventilating, and Air Conditioning
IGCC	Integrated-Gasification Combined-Cycle
IRM	Installed Reserve Margin
IRP	Integrated Resource Planning
kW	Kilowatt(s)
kWh	Kilowatt Hour(s)
LED	Light Emitting Diode
LMP	Locational Marginal Pricing
LNG	Liquid Natural Gas
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

Acronym	Meaning
MATS	Mercury and Air Toxics Standards
MMBTU	Million British Thermal Unit(s)
MMCF	Million Cubic Feet
MW	Megawatt(s)
MWh	Megawatt Hour(s)
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
NGCS	North Carolina General Statute(s)
NO_x	Nitrogen Oxide
NODA	Notice of Data Availability
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
PJM	PJM Interconnection, L.L.C.
Plan	2018 Integrated Resource Plan
PLEXOS	PLEXOS Model
PPA	Power Purchase Agreement
PPB	Parts Per Billion
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
RACT	Reasonable Available Control Technology
REC	Renewable Energy Certificate(s)
REPS	Renewable Energy and Energy Efficiency Portfolio Standard (NC)
RFC	Reliability First Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RIM	Ratepayer Impact Measure
RPM	Reliability Pricing Model
RPS	Renewable Energy Portfolio Standard (VA)
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SB 1418	Senate Bill 1418
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
ST	Short-Term
STAP	Short-Term Action Plan
TCJA	Tax Cuts and Jobs Act of 2017
TRC	Total Resource Cost
Va. Code	Code of Virginia
VCHEC	Virginia City Hybrid Energy Center
VOW	Virginia Offshore Wind Coalition
VOWDA	Virginia Offshore Wind Development Authority
VSAPCB	Virginia State Air Pollution Control Board
WACC	Weighted Average Cost of Capital
WEA	Wind Energy Area

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTEGRATED RESOURCE PLAN OVERVIEW

Virginia Electric and Power Company (the "Company") hereby files its 2018 Integrated Resource Plan ("2018 Plan") with the Virginia State Corporation Commission ("SCC") in accordance with § 56-599 of the Code of Virginia (or "Va. Code") and the SCC's guidelines issued on December 23, 2008. The Company also files the 2018 Plan 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 2018 Plan was prepared for the Dominion Energy 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 current provisions of Virginia and North Carolina law, the Company prepares an integrated resource plan (generally, "Plan") for filing in each jurisdiction every year.[1] On May 1, 2017, the Company filed its 2017 Plan with the SCC (Case No. PUR-2017-00051) and with the NCUC (Docket No. E-100, Sub 147). On March 12, 2018, the SCC issued its Final Order finding the 2017 Plan ("2017 Plan Final Order") reasonable and in the public interest for the specific and limited purpose of filing the planning document as mandated by Va. Code § 56-597 *et seq*. On April 16, 2018, the NCUC issued an Order accepting the 2017 Plan as complete and fulfilling the requirements set out in NCUC Rule R8-60.[2]

The Company is committed to addressing concerns and requirements identified by the SCC or the NCUC in prior relevant orders that continue to be applicable, as well as current and pending provisions of state and federal law. Notably, the Plan continues to evaluate compliance with the likely greenhouse gas ("GHG") regulations that may be promulgated by the Commonwealth of Virginia or the U.S. Environmental Protection Agency ("EPA"), or both. Since 2014, key elements of each of the Company's Plans have focused on compliance with the EPA's proposed Clean Power Plan ("CPP"). On March 28, 2017, however, President Trump issued an Executive Order directing the administrator of the EPA to begin the process of reviewing the CPP and, if appropriate, to revise or rescind the rule as soon as practicable.

On April 3 and 4, 2017, in response to the Executive Order, the EPA issued notices announcing that it was initiating a review of the entire CPP and the 111(b) rules.[3]

On October 16, 2017, the EPA published a proposal to repeal the CPP, which did not include a replacement rule. However, on December 28, 2017, the EPA issued an advanced notice of proposed rulemaking to solicit input on whether it should proceed with a replacement rule, and if so, what the scope of such a rule should be. The EPA has conducted public hearings on its proposed repeal of the CPP and conducted public listening sessions on the subject in February and March 2018.

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[1] Effective July 1, 2018, Va. Code § 56-599 A requires the Company to file an updated integrated resource plan in Virginia to "by May 1, in each year immediately preceding the year the utility is subject to a triennial review filing." The Company is subject to triennial review filings beginning in 2021 and continuing every three years thereafter. In North Carolina, NCUC Rule R-60(h)(1) requires the Company to file an integrated resource plan every two years. Accordingly, after the 2018 Plan, the next full integrated resource plan will be filed by May 1, 2020. The Company will comply with all applicable rules and guidelines regarding filing a narrative summary or update report in 2019.

[2] The April 16, 2018 NCUC Order also accepted the Company's REPS compliance plan.

[3] The 111(b) rules set standards of performance for GHG emissions from new, modified, or reconstructed EGUs.

Given these events, the Company no longer believes the CPP to be a "current" or "pending" regulation. Nevertheless, based on a broad reading of the SCC's directive in its 2017 Plan Final Order that the Company's future Plans contain plans that comply with the requirement of Va. Code § 56-599 B 9 to include "the most cost effective means of complying with current and pending state and federal environmental regulations," the Company provides a build plan under the CPP and the resulting net present value ("NPV") analysis in Appendix 1B in this 2018 Plan. In addition, the Company anticipates that some form of carbon dioxide ("CO_2") regulation may happen at the federal level and, as a result, it has assessed a generic federal carbon program (the "Federal CO_2 Program") in this 2018 Plan.

The Company also anticipates that there may be some form of carbon regulation at the state level. In the 2018 Regular Session, the Virginia General Assembly considered legislation through which Virginia would join the Regional Greenhouse Gas Initiative ("RGGI"). Initiated in 2009, RGGI is a collaborative effort to cap and reduce CO_2 emissions from the power sector currently among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.[4] The legislation failed, but the General Assembly could reconsider such legislation in the future. Accordingly, the Company has assessed the effects of joining RGGI on the current and future generation portfolio.

Separate from the legislative process, former Virginia Governor McAuliffe issued Executive Directive 11 ("ED-11") in May 2017 directing the Virginia Department of Environmental Quality ("DEQ") to draft regulations that would cap CO_2 emissions from Virginia's electric generating units ("EGUs"). On November 7, 2017, the DEQ released a draft proposal to reduce carbon emissions from fossil fuel-fired EGUs in Virginia pursuant to ED-11 (the "Virginia RGGI Program" or "Virginia RGGI"). The proposal seeks to establish a CO_2 emissions cap-and-trade program in Virginia with intended linkage to RGGI, including most of the elements of the modifications to the RGGI model rule finalized by RGGI in December 2017. A more detailed description of the Virginia RGGI Program, as well as RGGI itself, is included in Chapter 3. In light of this action by the Commonwealth of Virginia, the Company has also elected to assess the impacts of state-level carbon regulation in the form of Virginia RGGI in this 2018 Plan. A few points regarding the proposed Virginia RGGI Program are worth noting. As detailed in Section 3.1.3.1, the Company maintains:

- Virginia's linkage to RGGI will encourage electricity imports from out-of-state sources that are more carbon-intensive. The program will result in a significant increase in power imports while highly-efficient and lower-emitting natural gas combined-cycle ("NGCC") facilities in Virginia will run less;
- Reductions in carbon emissions in Virginia, as a result of the increased use of imported power, will be offset by emission increases elsewhere within the North American Electric Reliability Corporation ("NERC") Eastern Interconnect ("EI"), which includes all of PJM and the RGGI region;
- Increased imports of more carbon-intensive power will result in the carbon footprint per customer in Virginia increasing by about 5.7% by 2030; and
- Linking to RGGI could impose over $500 million in additional cost to Virginia customers during the 2020 to 2030 period.

As in prior Plans, the Company's objective in the 2018 Plan is to identify a 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,

[4] New Jersey, an original participant in RGGI, withdrew from the program in 2013, but has recently announced that it will initiate a process to rejoin the program.

and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing rate stability, increasing energy independence, promoting economic development, and incorporating input from stakeholders—will help the Company meet growing demand while protecting customers from a variety of potential challenges and negative impacts.

The 2018 Plan, like its predecessors, presents a range of alternatives representing plausible paths forward for the Company to meet the future energy needs of its customers. Specifically, the Company presents five different alternative plans (collectively, the "Alternative Plans") designed to meet customers' needs in the future under different carbon regulation scenarios.

The Company primarily used the PLEXOS model ("PLEXOS"), a utility modeling and resource optimization tool, to develop this 2018 Plan over the 25-year period beginning in 2019 and continuing through 2043 (the "Study Period"), using 2018 as the base year. The 2018 Plan is based on the Company's current assumptions regarding load growth, commodity prices, 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.

The Company's comprehensive planning process considers significant emerging policy, market, and technical developments that could impact its operations and, in turn, its customers. On the policy front, these developments include the passage of the Grid Transformation and Security Act of 2018 (the "GTSA"), which was recently signed into law in Virginia and will become effective July 1, 2018. The GTSA established a number of policy objectives, including encouraging grid transformation projects and renewable energy generation, and supporting an increased focus on energy efficiency programs. In the 2017 Plan Final Order, the SCC directed the Company to "include detailed plans to implement the mandates contained in [the GTSA]" in the 2018 Plan. The Company discusses its GTSA-related plans in Chapter 7.

On the market front, significant emerging developments include the cost effectiveness of solar photovoltaic ("PV") technology, which is currently cost competitive with other more traditional forms of generation like combined-cycle ("CC") natural gas. Each of the Alternative Plans includes a considerable amount of solar resources. This is due to the zero-emission characteristics of solar generation and because the installed cost of solar PV generation is a cost-effective option. The Alternative Plans call for solar additions ranging from approximately 5,000 MW (nameplate) to approximately 7,000 MW (nameplate) during the 25-year Study Period. Within the shorter 15-year period of 2019 to 2033 (the "Planning Period"), the Alternative Plans call for solar additions ranging from approximately 4,500 MW (nameplate) to approximately 6,400 MW (nameplate).

The 2018 Plan includes for modeling purposes "utility-scale" solar facilities that are assumed to be between 20 MW and 80 MW in size and predominately interconnected to the Company's transmission network. In reality, solar PV can be a collection of different-sized facilities ranging from 5 kilowatts ("kW") to 100 MW or more, which may be interconnected along the Company's transmission or distribution network.

As encouraged by the GTSA, the Company is taking steps to modernize its electric power grid. A modernized grid will create a more dynamic system that is better able to respond to the growth of utility-scale solar facilities and the proliferation of smaller, widely-dispersed distributed energy resources ("DERs"). A discussion of the Company's grid modernization efforts is included in Chapter 5.

Included in this 2018 Plan are sections on load forecasting (Chapter 2), existing resources and resources currently under development (Chapter 3), planning assumptions (Chapter 4), and future resources, including grid modernization (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 the Alternative Plans. In Chapter 6, the Company compares the Alternative Plans by weighing the costs of those plans against the risks of the plans using a comprehensive risk analysis. This analysis allowed the Company to examine the Alternative Plans given significant industry uncertainties, such as environmental regulations, commodity and construction prices, and resource mix. Also included in Chapter 6 is an analysis that compares the customer rate impact of each of the Alternative Plans. This analysis assumes the Company maintains its current customer base and realizes the customer growth forecasted in this 2018 Plan. Current law allows certain customers to purchase energy and capacity from competitive service providers. To the extent the Company's customer base declines, all other things being equal, then the rate increases depicted in this analysis will likely be higher.

Finally, a short-term action plan ("STAP") is included in Chapter 7, which discusses the Company's specific actions to support the 2018 Plan over the next five years (2019 to 2023). The Company maintains that the STAP represents the short-term path forward that 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 always, it should be noted 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 any particular project. Similarly, inclusion of a unit retirement in a plan should be considered as tentative only; the Company has not made any decision regarding the retirement of any generating unit. Conversely, not including a specific project or retirement in a given year's plan does not preclude the Company from including that project or retirement 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

Headquartered in Richmond, Virginia, the Company 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 18,611 MW of generation capacity, including approximately 346 MW of fossil-fueled and renewable non-utility generation ("NUG") resources, approximately 6,600 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV, and approximately 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, hydroelectric, pumped storage, biomass, and solar facilities. Additionally, the Company purchases capacity and energy from NUGs and the PJM market.

1.3 2018 INTEGRATED RESOURCE PLANNING PROCESS

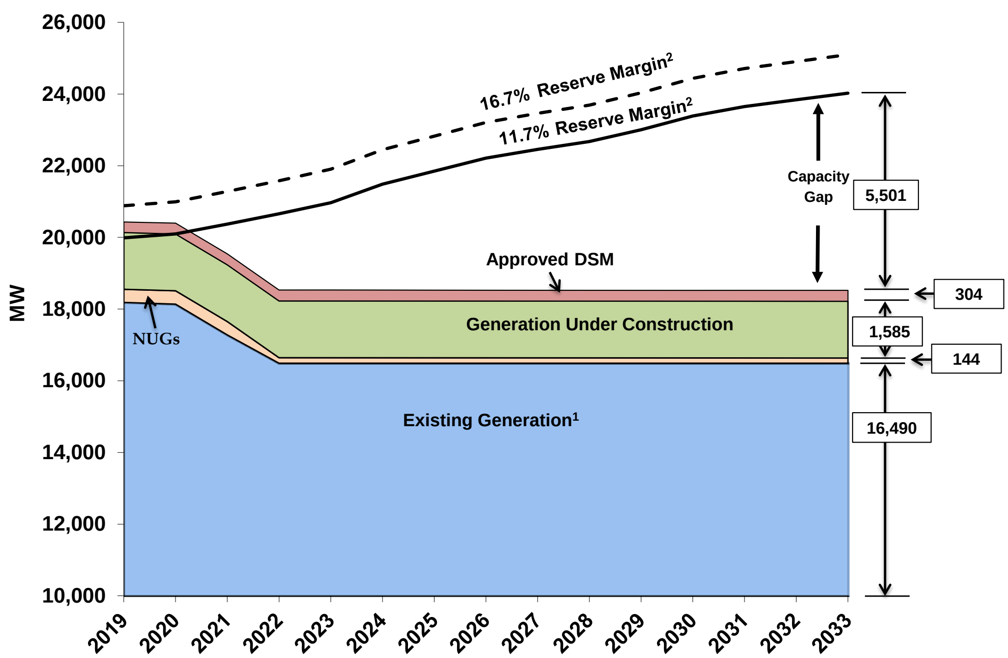
In order to meet future customer needs at the lowest reasonable cost while maintaining reliability and flexibility, the Company must take into consideration the uncertainties and risks associated with the energy industry. Uncertainties assessed in this 2018 Plan include:

- 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);
- potential state carbon regulation programs such as the Virginia RGGI Program or RGGI;

- fuel prices;
- cost and performance of energy technologies;
- renewable energy goals, including integration of intermittent renewable generation;
- current and future DSM programs; and
- retirement of Company-owned generation units.

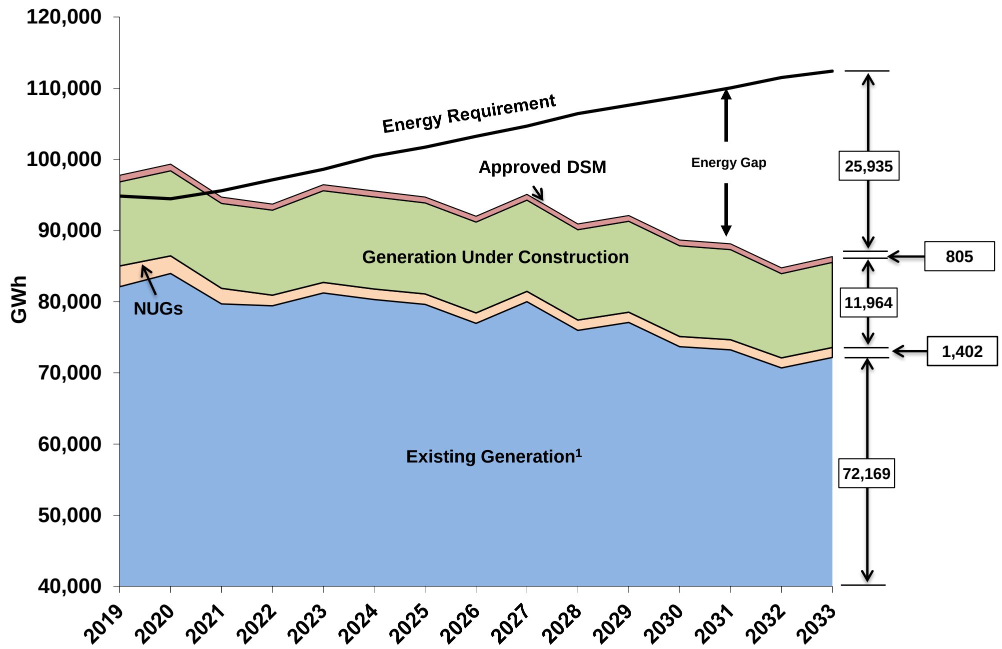
The Company developed this 2018 Plan based on its evaluation of various supply- and demand-side alternatives, and in consideration of acceptable levels of risk, that maintain the option to develop a diverse mix of resources for the benefit of its customers. Various planning groups throughout the Company 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 the DOM LSE is expected to experience annual increases of 1.4% in both future summer peak demand and energy requirements over the Planning Period (2019 to 2033). Collectively, these elements assisted in determining updated capacity and energy requirements as illustrated in Figures 1.3.1 and 1.3.2.

Figure 1.3.1 - Current Company Capacity Position (2019 - 2033)



Note: The values in the boxes represent total capacity in 2033.
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 (2019 - 2033)



Note: The values in the boxes represent total energy in 2033.
1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

1.3.1 CARBON REGULATION

Despite the current uncertainty regarding future federal policies, the Company believes that carbon regulation of power station emissions is virtually assured in the future. The Company is a leader in the transition to a lower carbon future and its past, present, and planned future actions provide evidence of that commitment. The Company began this transition well before the emergence of the federal CPP and even before the emergence of RGGI.

The Company has supported efforts to reduce GHG and lower its carbon intensity with several actions. First, the Company has added 56 MW (nameplate) of solar generation through the addition of the Scott, Whitehouse, and Woodland solar projects. Second, the Company has steadily reduced the coal-powered portion of its fleet serving Virginia customers. Third, new generating units using highly-efficient CC technology and powered by lower-emissions natural gas, have been placed into service. In addition, the nuclear units at Surry and North Anna continue, by far, to be the Company's most abundant source of zero-emissions generation, which have lowered and continue to lower the Company's carbon footprint by approximately 22 million tons of CO_2 per year. To put this into perspective, the Company's nuclear fleet is equivalent to over 100,000 acres of solar PV.

As a result of these actions, from 2000 to 2017, the carbon intensity—measured by the annual amount of CO_2 emissions emitted per megawatt-hour ("MWh") of net generation—of the Company's units serving Virginia jurisdictional customers has declined by 35%. At the same time, power production by these units has increased by 14%. The carbon intensity for all electric generation in Virginia, including the generation units owned by the Company and other sources, compares very favorably to nearby states according to data from the U.S. Energy Information Administration

(“EIA”).[5] Based on 2016 EIA data, Virginia ranks 11th among 13 states in PJM’s control area, making it the third lowest state in terms of carbon intensity.

Planned future action by the Company will continue to support the transition to a lower carbon future. For example, the Company plans to place over 1,200 MW of fossil-fueled generation into cold reserve by the end of the year. The Company is also moving aggressively to expand its use of renewable resources, with its investment in solar projects in Virginia and North Carolina approaching $1 billion with a total of 1,350 MW of capacity in service, under construction, or under development. Additionally, the Company is one of the largest generators in the nation using renewable biomass and is developing an offshore wind demonstration project to be located off the coast of Virginia Beach. Further, the Company is in the process of evaluating a hydroelectric pumped storage facility in southwestern Virginia that could be supported by generators using renewable energy.

1.3.2 SCC’s 2017 PLAN FINAL ORDER

As mentioned above, the SCC’s 2017 Plan Final Order found the 2017 Plan to be in the public interest for the specific and limited purpose of filing the planning document. The SCC noted that Virginia Governor Northam had signed the GTSA into law, and directed the Company to evaluate the GTSA in this 2018 Plan: “The Commission…directs that Dominion’s future IRPs, beginning with the IRP filed on May 1, 2018, shall include detailed plans to implement the mandates contained in that legislation….” The Company discusses its GTSA-related plans in Chapter 7.

1.4 2018 PLAN

Consistent with past Plans, the Company presents five Alternative Plans that represent plausible future paths for meeting the future electric needs of its customers. Given the current status of the CPP, none of these Alternative Plans evaluates a generation portfolio expansion based on implementation of the CPP.[6] Instead, this 2018 Plan assesses the portfolio expansions necessary to meet compliance with the Virginia RGGI Program as proposed (with allowances allocated to generators under a consignment auction), with RGGI (with direct auction of allowances), and with a potential Federal CO_2 Program consistent with the forecast provided by ICF, a global energy consulting firm. As required, the Company has also included an Alternative Plan that estimates future generation expansion in a world where there are no new limits on CO_2 emissions. This Alternative Plan is only presented to measure the cost of GHG program compliance. But the Company fully expects that some form of GHG regulation or legislation is likely and is planning accordingly.

As noted above, while Virginia appears to be moving forward with state-level GHG regulation, little has been settled with respect to the exact rules surrounding future GHG regulation since the publication of the 2017 Plan.

Therefore, at this time, and as was the case in the 2015, 2016, and 2017 Plans, the Company did not identify a “Preferred Plan” or a recommended long-term path forward beyond the STAP. Rather, the Company is presenting the Alternative Plans that are described below. The Company believes the Alternative Plans represent plausible future paths for meeting the future electric needs of its customers.

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[5] EIA’s State Electricity Profiles are located at: https://www.eia.gov/electricity/state/.

[6] Nevertheless, the Company includes a CPP scenario in Appendix 1B. The Company also notes that RGGI is more restrictive than the originally-proposed CPP. The Company assesses a plausible future path complying with Virginia RGGI or RGGI in Alternative Plans B, C, and D.

All of the Alternative Plans were designed using least-cost planning techniques and are as follows:

- Plan A: No CO_2 Tax: This Alternative Plan assumes the highly unlikely scenario of no new regulations or restrictions on CO_2 emissions. Plan A selects significant levels of solar PV generation, as it is currently cost competitive with other traditional generation technologies as described above. Plan A serves as a least-cost baseline for comparing the results of the other plans.
- Plan B: Virginia RGGI (unlimited imports): This Alterative Plan was designed assuming that the Virginia RGGI Program is approved as proposed in the form of the current draft regulation issued by the State Air Pollution Control Board. Plan B assumes that the Company's compliance with RGGI under the Virginia RGGI Program is largely met through the use of more carbon intensive imported energy and capacity.
- Plan C: RGGI (unlimited imports): This Alternative Plan assumes that Virginia is a full member of RGGI. Plan C assumes that the Company's compliance with RGGI is largely met through the use of more carbon intensive imported energy and capacity.
- Plan D: RGGI (limited imports): This Alternative Plan assumes that Virginia is a full member of RGGI. Plan D assumes that the Company's compliance with RGGI is met through generation build within Virginia and limited imported power.
- Plan E: Federal CO_2 Program: This Alternative Plan assumes that Virginia does not join RGGI (either directly or through the Virginia RGGI Program) and that federal CO_2 legislation or the regulatory equivalent is enacted beginning in 2026.

Going forward, the Company will continue to analyze both the operational implications and challenges of meeting carbon restrictions, adding renewable generation, and keeping existing generation operational, including coal, oil, and biomass units, when doing so is in the best interest of customers and the Commonwealth in compliance with federal and state laws and regulations. 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.

As mentioned above, to assess the uncertainty and risks associated with external market and environmental factors, the Company developed the Alternative Plans representing plausible future paths the Company could follow to meet the future electric power needs of its customers. There are approximately 5,000 MW (nameplate) of new solar generation within the Study Period (2019 to 2043), with at least approximately 4,500 MW (nameplate) of new solar capacity being added by the end of the Planning Period (2019 to 2033).

The Alternative Plans also include the 12 MW (nameplate) Coastal Virginia Offshore Wind Project ("CVOW") as early as 2021; 760 MW (nameplate) of Virginia and North Carolina solar generation from NUGs either currently or expected to be under long-term contracts by 2020; and the 1,585 MW (nameplate) Greensville County Power Station which is currently under construction and planned to enter commercial operation by 2019. Additionally, the Alternative Plans include Company-owned Virginia utility-scale solar generation: the US-3 Solar 1 Facility, 142 MW (nameplate); and the US-3 Solar 2 Facility, 98 MW (nameplate). The US-3 Solar 1 and 2 Facilities are currently under development; the Company tentatively plans to file with the SCC for required approvals in 2018.

All of the Alternative Plans also include the Company's placement of 10 generating units into cold reserve in 2018. Bellemeade Power Station, Bremo Power Station Units 3 and 4, and Mecklenburg Power Station Units 1 and 2 were placed into cold reserve in April 2018. Pittsylvania Power Station will be placed into cold reserve in August 2018. Chesterfield Power Station Units 3 and 4 and Possum Point Power Station Units 3 and 4 will be placed into cold reserve in December 2018.

These units are currently planned to remain in cold reserve until 2021. “Cold reserve” does not mean permanent retirement. These units, which total 1,292 MW of generation, can be reactivated in approximately six months if system needs and market conditions dictate. The Company will continue to maintain all required environmental permits for the units and continue to pay property taxes to the localities in accordance with the relevant property tax assessment.

The Alternative 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 2032 and 2033, respectively, extending the licensed life to 2052 and 2053, respectively, and the license extensions for North Anna Units 1 and 2 in 2038 and 2040, extending the licensed life to 2058 and 2060, respectively.

The Alternative Plans are discussed further below and are summarized in Figure 1.4.1.

Figure 1.4.1 - Alternative Plans

Year	Plan A: No CO_2 Tax	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
Approved DSM: 304 MW, 805 GWh by 2033					
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1)
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT AERO CT SLR (480 MW) CH5-6	CT AERO CT SLR (480 MW) CH5-6	CT AERO CT SLR (480 MW) CH5-6	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (400 MW)
2025	CT SLR (400 MW)	CT AERO CT SLR (400 MW) CL1-2	CT AERO CT SLR (400 MW) CL1-2	2X1 CC SLR (400 MW) CL1-2	CT SLR (480 MW)
2026	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2027	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)
2028	SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)
2029		CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (400 MW)
2030	CT	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (320 MW)
2031	CT SLR (160 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (80 MW)
2032	CT SLR (240 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)	SLR (480 MW)
2033	SLR (80 MW)	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); CT AERO: Aero-derivative CT (119 MW); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar Non-Utility Generator; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.
2) These units entered into cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These units are planned to enter cold reserve in December 2018.

Common elements of the Alternative Plans

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

- **Demand-Side Resources:**
  - approved DSM programs reaching approximately 304 MW, 805 GWh by 2033;
- **Generation under Construction:**
  - Greensville County Power Station, approximately 1,585 MW of natural gas-fired CC capacity by 2019;
- **Generation under Development:**
  - US-3 Solar 1, approximately 142 MW (nameplate) of Virginia utility-scale solar generation by 2020;
  - CVOW, approximately 12 MW (nameplate) of offshore wind as early as 2021;
  - US-3 Solar 2, approximately 98 MW (nameplate) of Virginia utility-scale solar generation by 2021;
- **Potential Generation:**
  - eight combustion turbine ("CT")[7] plants totaling approximately 3,664 MW by 2033;
  - solar PV generation totaling approximately 4,480 MW (nameplate) by 2033;
- **NUGs:**
  - 660 MW (nameplate) of North Carolina solar NUGs by 2020;
  - 100 MW (nameplate) of Virginia solar NUGs by 2020;
- **Extensions:**
  - Surry Units 1 and 2, license extensions of 20 years by 2032 and 2033;
  - North Anna Units 1 and 2, license extensions of 20 years by 2038 and 2040;
- **Cold Reserve Units:**
  - Bellemeade Power Station (267 MW) in April 2018;
  - Bremo Power Station Units 3 and 4 (227 MW) in April 2018;
  - Chesterfield Power Station Units 3 and 4 (261 MW) in December 2018;
  - Mecklenburg Power Station Units 1 and 2 (138 MW) in April 2018;
  - Pittsylvania Power Station (83 MW) in August 2018; and
  - Possum Point Power Station Units 3 and 4 (316 MW) in December 2018.
- **Retirements:**[8]
  - Bellemeade Power Station (267 MW) to be potentially retired by 2021;
  - Bremo Power Station Units 3 and 4 (227 MW) to be potentially retired by 2021;
  - Chesterfield Power Station Units 3 and 4 (261 MW) to be potentially retired by 2021;

[7] All references regarding new CT units throughout this document refer to installations of a bank of two CT units.
[8] The generating units listed should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date.

- Mecklenburg Power Station Units 1 and 2 (138 MW) to be potentially retired by 2021;
- Pittsylvania Power Station (83 MW) to be potentially retired by 2021;
- Possum Point Power Station Units 3 and 4 (316 MW) to be potentially retired by 2021;
- Possum Point Power Station Unit 5 (786 MW) to be potentially retired by 2021; and
- Yorktown Power Station Unit 3 (790 MW) to be potentially retired by 2022.

Beyond these common elements, additional resources and retirements included in the Alternative Plans are listed below:

- **Potential Generation:**
  - Plan A: No CO_2 Tax includes one additional CT plant of approximately 458 MW;
  - Plan B: Virginia RGGI (unlimited imports) includes three additional CT plants of approximately 1,374 MW, two CT Aero-derivatives ("Aeros") of 238 MW, and an additional 1,920 MW (nameplate) of solar by 2033 (totaling 6,960 MW (nameplate) by 2043);
  - Plan C: RGGI (unlimited imports) includes three additional CT plants of approximately 1,374 MW, two CT Aeros of approximately 238 MW, and an additional 1,920 MW (nameplate) of solar by 2033 (totaling 6,960 MW (nameplate) by 2043);
  - Plan D: RGGI (limited imports) includes one 2x1 CC unit of approximately 1,062 MW, one additional CT plant of approximately 458 MW, one CT Aero of approxmately 119 MW, and an additional 1,920 MW (nameplate) of solar by 2033 (totaling 6,960 MW (nameplate) by 2043); and
  - Plan E: Federal CO_2 Program includes an additional 1,280 MW (nameplate) of solar by 2033 (totaling 6,960 MW (nameplate) by 2043).
- **Retirements:**
  - Plan B: Virginia RGGI (unlimited imports), Plan C: RGGI (unlimited imports) and Plan D: RGGI (limited imports) include the potential retirements of Chesterfield Units 5 (336 MW) and 6 (670 MW) by 2023, and Clover Units 1 (220 MW)[9] and 2 (219 MW)[9] by 2025.

Figure 1.4.2 illustrates the renewable resources included in the Alternative Plans over the Study Period (2019 to 2043).

[9] The MW reflect the Company's 50% ownership in Clover.

Figure 1.4.2 - Renewable Resources in the Alternative Plans through the Study Period

	Nameplate MW	Plan A: No CO_2 Tax	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
Existing Resources[1]	533	x	x	x	x	x
VCHEC Biomass	61	x	x	x	x	x
Solar NUGs[2]	760	x	x	x	x	x
CVOW	12	x	x	x	x	x
US-3 Solar 1	142	x	x	x	x	x
US-3 Solar 2	98	x	x	x	x	x
Solar PV	Varies	4,960	6,960	6,960	6,960	6,960

Note: 1) Existing Resources include hydro-electric, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2020.

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. The capacity and energy associated with all Alternative Plans are illustrated in Appendix 1A.

The 2018 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 rates from generating units serving Virginia by 88% for nitrogen oxide ("NO_x"), 97% for mercury ("Hg"), and 98% for sulfur dioxide ("SO_2") from 2000 levels through 2017.

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

The large generators listed as potential retirements in each of the Alternative Plans were evaluated for repowering and co-firing. The current results of this analysis are discussed in Section 6.9.

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. 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 Alternative Plans.

While not definitively choosing one plan or a combination of plans beyond the STAP, the Company remains committed to pursue the development of resources that meets the needs of customers while supporting the fuel diversity needed to minimize risks associated with changing market conditions, industry regulations, and customer preferences.

1.5 COST AND RATE IMPACT OF THE ALTERNATIVE PLANS

All of the Alternative Plans envisioning compliance with state (Plans B, C, and D) or federal (Plan E) carbon regulations would impose higher costs on customers, but the costs and rate impacts of the possible scenarios vary. As discussed in Section 6.5, the NPV through 2043 of costs associated with the four plans including carbon regulation range from $1.54 billion to $4.04 billion greater than the NPV of the baseline plan (Plan A). Specifically, the incremental NPVs associated with each of the carbon-regulating Alternative Plans are $1.54 billion (Plan B); $3.71 billion (Plan C); $4.04 billion (Plan D); and $3.09 billion (Plan E).

As discussed in Section 6.6, the rate impact analysis of the Alternative Plans shows that carbon regulation compliance will lead to higher bills for the Company's customers. By 2030, implementation of Plans B, C, D, or E would result in typical monthly residential bills (for 1,000 kilowatt hours ("kWh") of usage) ranging from 2.2% (Plan E) to 5.6% (Plan D) higher than under the baseline plan (Plan A). Expressed in 2018 dollars, the additional monthly cost of electricity by 2030 for a typical residential customer would be $3.59 under Plan B, $5.01 under Plan C, $5.81 under Plan D, and $2.23 under Plan E.

CHAPTER 2 – LOAD FORECAST

2.1 FORECAST METHODS

The Company uses two econometric models with an end-use orientation to forecast sales, energy, and peak demand. The first is a customer class level sales model ("Sales Model") and the second is a system level hourly load model ("Peak and Energy Model"). The models used to produce the Company's load forecast have been developed, enhanced, and re-estimated annually for over 20 years. Both models are estimated over a rolling 30-year historical period as each long-term forecast is developed. The historical period used to develop the current 2018 Plan Load Forecast spanned the period from October 1988 through September 2017.

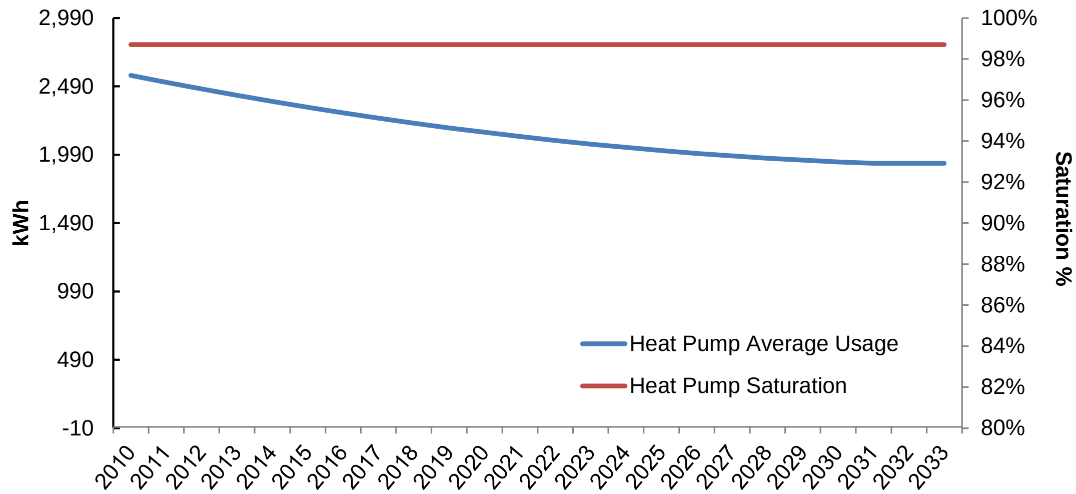
The Sales Model incorporates separate monthly sales equations for the residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customer classes, as well as other load serving entities ("LSEs") in the Dominion Energy Zone ("DOM Zone"), all of which are in the PJM RTO. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load. In addition to developing a sales forecast, the primary role of the Sales Model is to provide estimates of historical and projected weather sensitive appliance stocks and non-weather sensitive base demand for use as exogenous variables in the Peak and Energy Model.

Variables included in each of the class monthly sales equations are as follows:

- **Residential sales equation:** Income, electric prices, unemployment rate, number of customers, appliance saturations, appliance efficiencies, 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 authorities, 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:** Residential sales 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 residential sales equation also relies on an algorithm that dynamically adjusts forecasted appliance saturation and usage based on historical trends. These historical trends are determined from appliance data collected through surveys of the Company's residential customers. Figure 2.1.1 shows historical and forecasted saturation and usage data for residential heat pumps.

Figure 2.1.1 - Residential Heat Pump (Cooling) Saturation and Usage



The most recent residential customer appliance survey was completed in 2016. One noteworthy item from the results of that survey is with respect to residential lighting. Between the time of the 2013 appliance survey and the 2016 appliance survey, a significant change was observed in the penetration of energy-efficient light emitting diode ("LED") lighting among the Company's residential customers. In order to account for this new lighting trend, the Company modified its residential sales modeling in a manner that will dynamically reduce forecasts of residential lighting load as LED lighting penetration increases. The residential lighting saturation and usage utilized in the load forecast for incandescent, compact florescent light ("CFL"), and LED lighting for the 2018 Plan is shown in Figures 2.1.2 and 2.1.3, respectively. This saturation and usage data was based on an analysis of appliance survey results.

Figure 2.1.2 - Residential Lighting Saturation

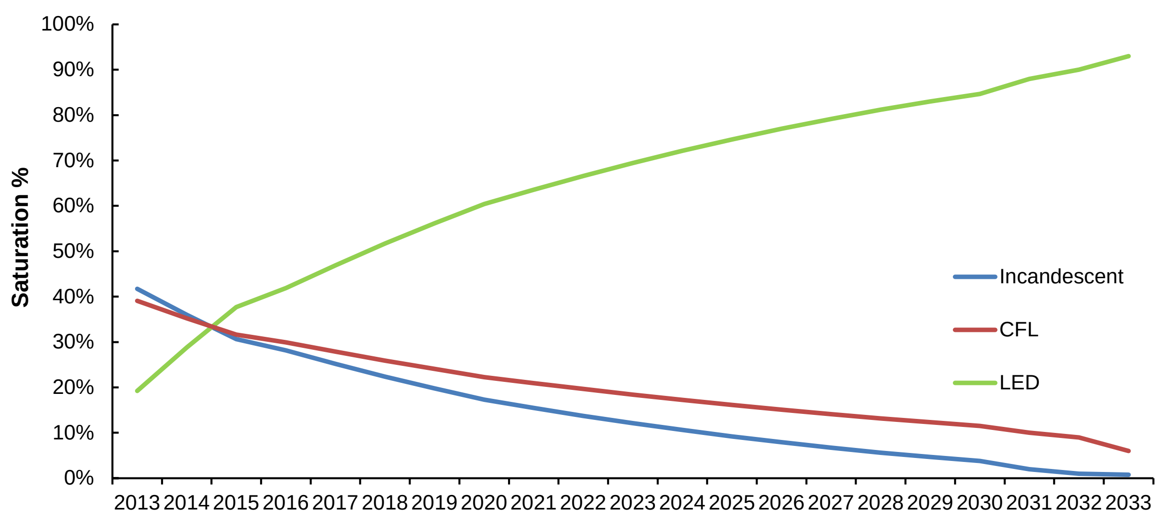
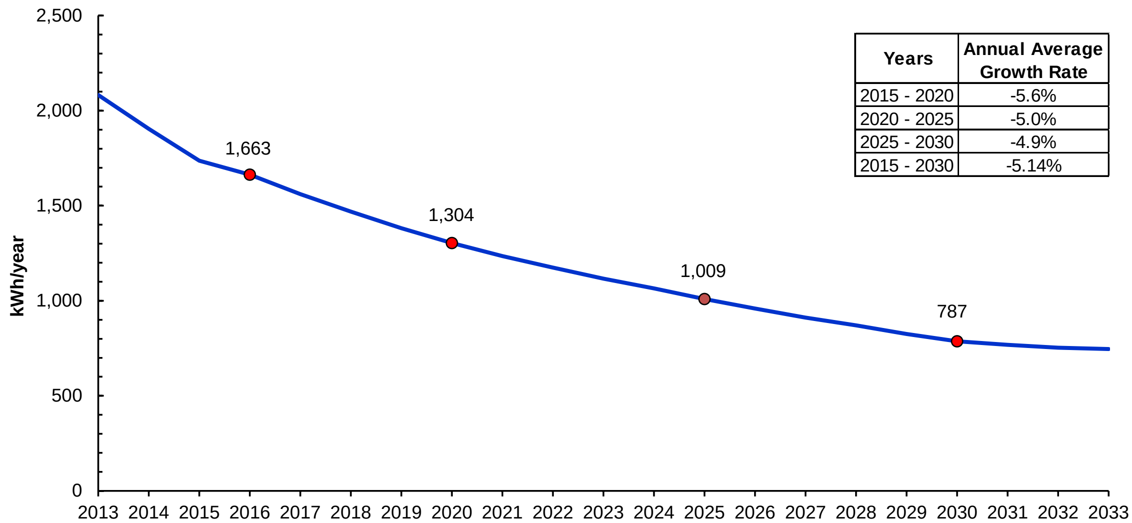


Figure 2.1.3 - Residential Lighting Usage



The Company's second model, the Peak and Energy Model, is comprised of 24 separate equations, one for each hour of the day, with adjusted DOM Zone loads as the dependent variable. Prior to estimating the Peak and Energy Model equations, historical hourly loads are adjusted by adding back historical distributed solar generation and load management reductions.

Each Peak and Energy Model equation includes a non-weather sensitive base demand variable, derived from the estimated aggregate non-weather sensitive base demand components from the Sales Model as well as a detailed specification of weather variables. The weather variables include interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations in conjunction with residential heating and cooling appliance stocks. The Peak and Energy Model also employs indicator variables to capture monthly, day of week, time of day, holiday, and other seasonal effects, as well as unusual widespread outage producing events such as hurricanes.

The forecast of expected DOM Zone monthly and seasonal peaks and energy output is produced by simulating hourly demands from the estimated Peak and Energy Model over actual hourly weather from each of the past 30 years under projected economic conditions. The final forecasted zonal peak and energy values include subsequent adjustments for projected block loads from incremental new data centers, or other significant load additions not reflected in the hourly regression equations.

The final monthly peak and energy forecast for the DOM LSE is based on a regression of historical DOM LSE loads onto historical DOM Zone loads. The estimated coefficients are applied to the projected zonal loads resulting in a load forecast for the DOM LSE that is then adjusted for known firm contractual obligations in the forecast period.

2.2 HISTORY & FORECAST BY CUSTOMER CLASS & ASSUMPTIONS

The DOM Zone is typically a summer peaking system; however, during the winter periods of 2013/2014, 2014/2015, and 2017/2018, significant DOM Zone peaks were set at 19,978 MW, 21,867 MW, and 21,350 MW, respectively. The historical DOM Zone summer peak growth rate has averaged about 1.2% annually over the 2002 to 2017 period. The annual average energy growth rate over the same period is approximately 0.8%. Historical DOM Zone peak load and annual energy output along with a 15-year forecast are shown in Figures 2.2.1 and 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 1.4% 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 2018 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

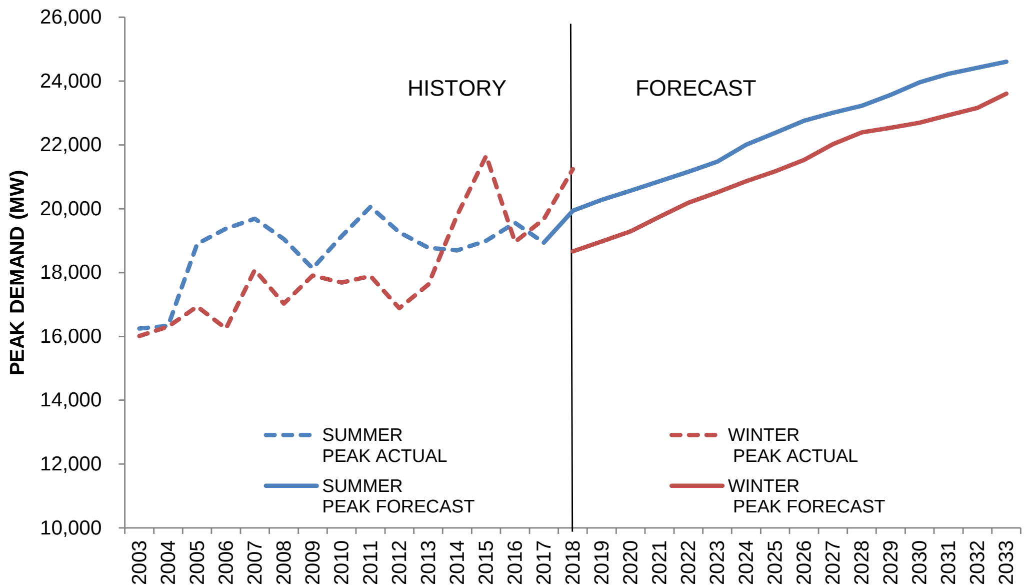


Figure 2.2.2 - DOM Zone Annual Energy

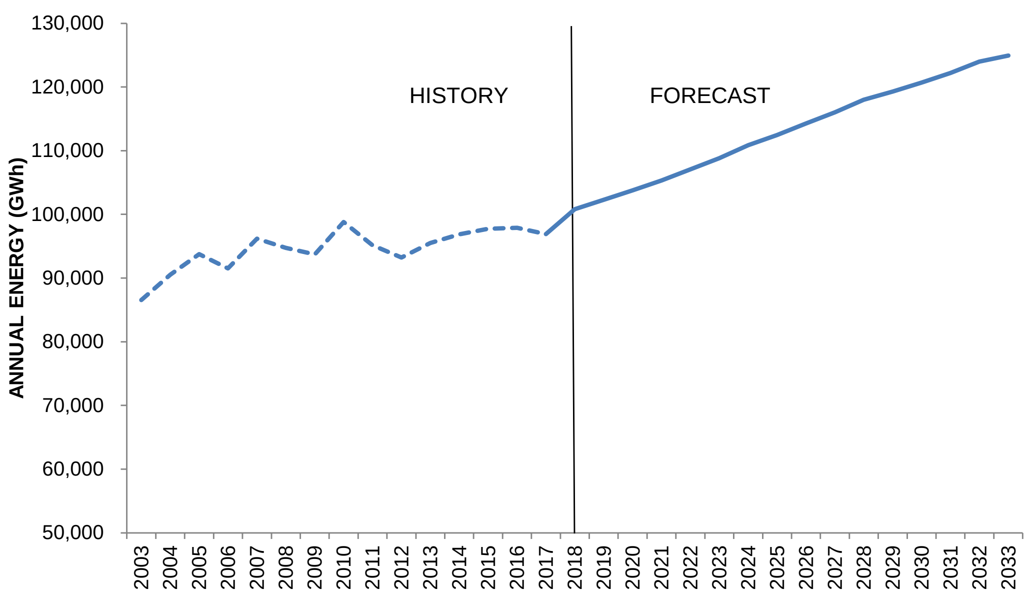


Figure 2.2.3 summarizes the final forecast of energy sales and peak load over the next 15 years. The Company's wholesale and retail customer energy sales are estimated to grow at annual rates of approximately 1.2% and 1.5%, respectively, over the Planning Period. Projected growth rates can diverge for a number of reasons, including weather and economic conditions.

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

	2018	2033	Compound Annual Growth Rate (%) 2018 - 2033
DOMINION ENERGY LSE			
TOTAL ENERGY SALES (GWh)	83,439	104,270	1.5%
Retail	81,838	102,367	1.5%
Residential	30,245	35,649	1.1%
Commercial	32,166	45,967	2.4%
Industrial	8,700	8,269	-0.3%
Public Authorities	10,443	12,175	1.0%
Street and Traffic Lighting	284	307	0.5%
Wholesale (Resale)	1,601	1,903	1.2%
SEASONAL PEAK (MW)			
Summer	17,417	21,499	1.4%
Winter	16,019	20,260	1.6%
ENERGY OUTPUT (GWh)*	88,148	109,248	1.4%
DOMINION ENERGY ZONE			
SEASONAL PEAK (MW)			
Summer	19,938	24,610	1.4%
Winter	18,666	23,608	1.6%
ENERGY OUTPUT (GWh)	100,809	124,945	1.4%

Notes: All sales and peak load have not been reduced for the impact of DSM.
*The DOM LSE energy output compound annual growth rate ("CAGR") is lower than the DOM LSE total energy sales due to the general absence of distribution losses associated with data centers.

Figures 2.2.4 and 2.2.5 provide comparisons of the DOM Zone summer peak load and energy forecasts included in the 2017 Plan and the 2018 Plan, as well as PJM's load forecast for the DOM Zone from its 2017 and 2018 Load Forecast Reports.[10] These figures also include historical peak load and energy.

[10] See http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx and http://www.pjm.com/~/media/library/reports-notices/load-forecast/2018-load-report.ashx.

Figure 2.2.4 - DOM Zone Peak Load Comparison

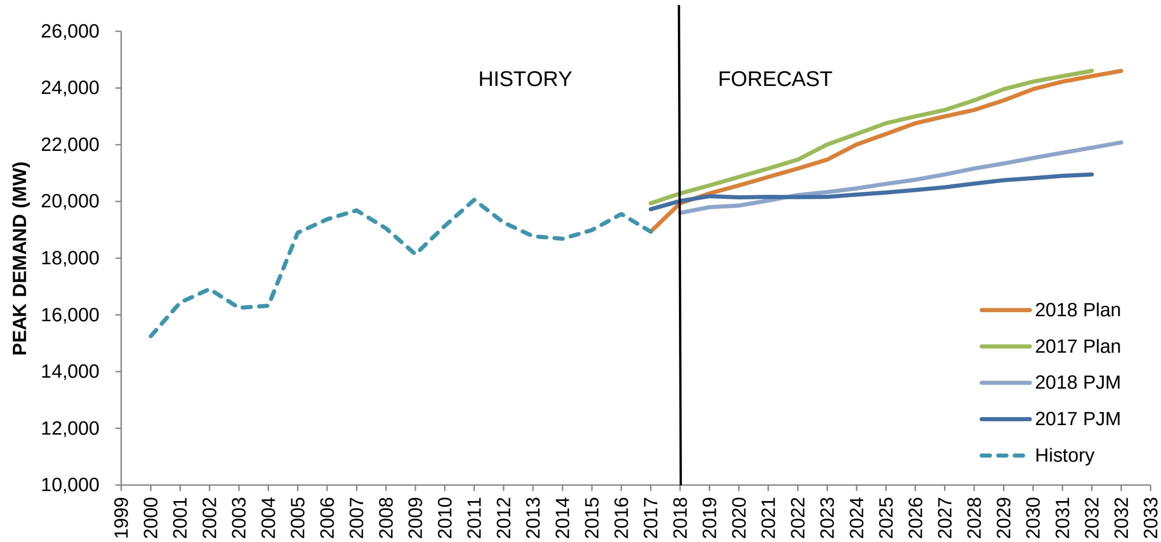
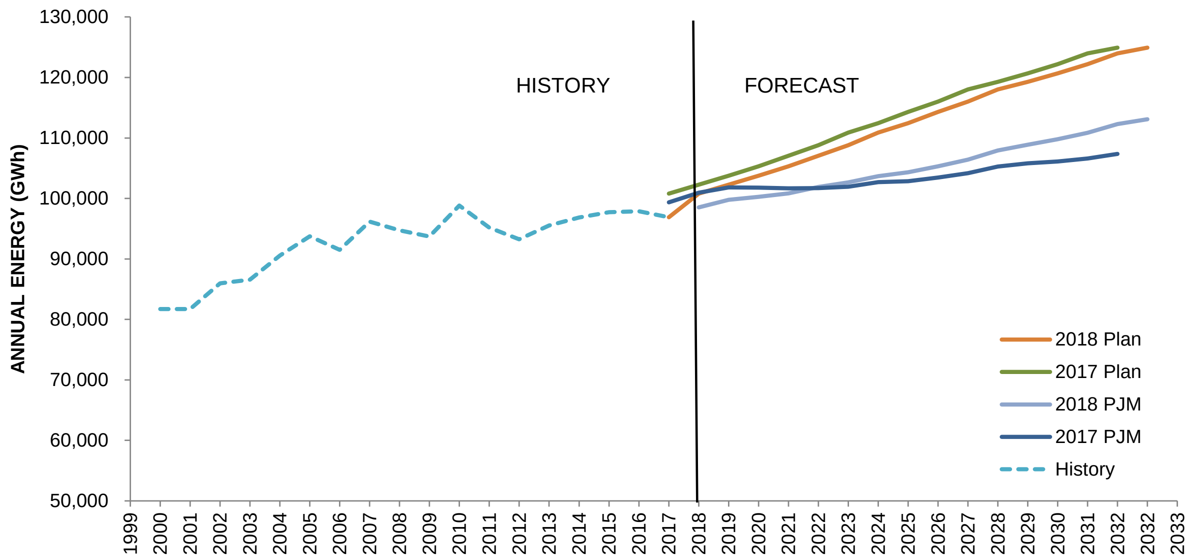


Figure 2.2.5 - DOM Zone Annual Energy Comparison



The economic and demographic assumptions that were used in the Company's load forecast models were supplied by Moody's Analytics, prepared in October 2017, 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 2018 Plan.

Figure 2.2.6 - Major Assumptions for the Sales and Peak and Energy Models

	2018	2033	Compound Annual Growth Rate (%) 2018 - 2033
DEMOGRAPHIC:			
Customers (000)			
Residential	2,329	2,708	1.01%
Commercial	244	277	0.85%
Population (000)	8,515	9,419	0.68%
ECONOMIC:			
Employment (000)			
State & Local Government	540	615	0.87%
Manufacturing	233	195	-1.18%
Government[1]	719	798	0.70%
Income ($)			
Per Capita Real Disposable	42,674	54,219	1.61%
Price Index			
Consumer Price (1982-84=100)	250	353	2.32%
VA Gross State Product (GSP)	461	620	1.99%

Note: (1) Government = State (Commonwealth of Virginia) + Local (County + Municipalities) + Federal Employment (Non-Military)

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 Great Recession of 2007 to 2009 and the subsequent slow rate of recovery. However, more recently, Virginia's economy was also negatively impacted by federal government budget cuts triggered by the mandated sequestration that went into effect in 2013 and continued through 2017. The sequestration adversely affected Virginia due to the Commonwealth's dependency on federal government spending, particularly in the area of defense. In spite of these economic head winds, the Virginia economy continued to grow at an annual average real GSP growth rate of approximately 1.0% during 2009 to 2016. As of October 2017, the seasonally-adjusted unemployment rate in Virginia approached 3.6%, which is approximately 0.5% below the national unemployment rate. Based on the input data provided by Moody's Analytics, the Virginia economy is expected to rebound further within the Planning Period. This is reflected in the projection of the Virginia GSP. Moody's Analytics' projection has a CAGR of 1.99%. In addition, Virginia per capita disposable income is projected to increase at a CAGR of 1.61%.

There are a number of indications supporting anticipated growth in the Virginia economy within the Planning Period. For example, given Virginia's large military footprint, approval increased federal defense spending should benefit the Virginia economy. The Commonwealth has also been aggressive in its economic development efforts by recruiting businesses that create jobs to add to the Virginia economy. Moreover, Virginia continues to have an attractive quality of life, strong K-12 and higher education systems, and as a result continues to be an attractive destination for young professionals, families, and retirees.

Residential housing starts and associated new homes are major 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, but began showing increased growth beginning

in 2012. According to Moody's Analytics, Virginia is expected to show significant improvement in housing starts in 2018, which is reflected as new customers in the load forecast.
Another driver of energy sales 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.

2.3 COMPARISON WITH PJM'S 2018 PEAK DEMAND FORECAST FOR THE DOM ZONE

For the second year running, PJM's DOM Zone 2018 peak demand forecast is lower than the Company's internal forecast for the DOM Zone. In Section 2.3 of the 2017 Plan, the Company detailed the major differences between the methods used by PJM in its load forecasting process and those used by the Company. This presentation also reflected how these methodological differences are causing the differences in the resulting forecasts. These differences still exist between PJM and the Company, which again have resulted in differing peak demand and energy forecasts.

In addition to the methodological differences addressed in the 2017 Plan, there are two new points that should be considered when comparing PJM's and the Company's load forecasts for the DOM Zone. First, PJM's 2018 15-year peak demand CAGR for the DOM Zone is approximately 0.8% annually. For energy, PJM predicts a 15-year CAGR of 0.9% for the DOM Zone. These figures represent a 100% and 80% increase, respectively, relative to PJM's 15-year peak demand and energy CAGR for the DOM Zone that was published in PJM's 2017 Load Forecast Report. According to PJM's Load Analysis Subcommittee,[11] the reasons for this increase were: (i) an increase in PJM's data center forecast; (ii) an adjustment to PJM's behind-the-meter generation ("BTMG") solar forecast; and (iii) adjustment to the "equipment index" used by PJM in its 2018 DOM Zone forecast. The equipment index is used by PJM to capture end use appliance saturation and efficiency gains used in its forecasting process. According to PJM, equipment index adjustments were made as a result of the diminishing likelihood of the CPP.

The second point to be considered in comparing load forecasts is with respect to PJM's forecasted 2018 winter peak demand for the DOM Zone. PJM issued its 2018 Load Forecast Report on December 28, 2017. During the first week of January 2018, the eastern United States, including Virginia, experienced a prolonged period of extreme cold winter weather. As specified in PJM's 2018 Load Forecast Report, the 90/10 forecasted winter peak demand for the DOM Zone is 19,512 MW. To be clear, the 90/10 forecast represents the 90th percentile forecasted peak demand level that, in theory, should only be realized or exceeded once every nine years on average. During the first week of January 2018, the actual peak demand for the DOM Zone exceeded PJM's 90/10 winter forecast peak demand level for the DOM Zone on five different occasions (see Figure 2.3.1) by an average of approximately 1,400 MW. By comparison, during that same week, the actual winter peak demand exceeded the Company's 90/10 winter peak demand forecast on two occasions by an average of approximately 40 MW. The Company understands that PJM has recognized this issue in its load forecasting and is in the process of revising their load forecasting methods.[12]

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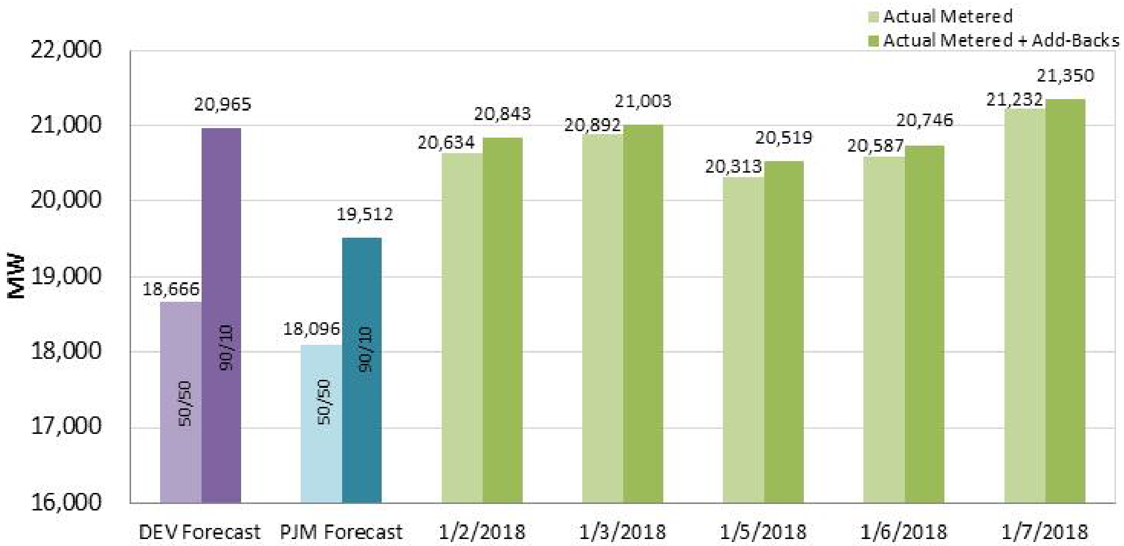
[11]See http://www.pjm.com/-/media/committees-groups/subcommittees/las/20170717/20170717-item-04-end-use-variable-revisions.ashx.

[12]See http://www.pjm.com/-/media/committees-groups/subcommittees/las/20180314/20180314-item-04-potential-load-forecast-enhancements.ashx.

Figure 2.3.1 – January 2018 Forecasted Peak and Metered Peaks



Note: Add-Backs include distributed solar generation and load management.

To address the differences between PJM's peak demand and energy forecast for the DOM Zone relative to the Company's forecast, the Company has included in this 2018 Plan a sensitivity case that compares the change in the generation expansion plans (and cost) when using PJM's load forecast versus the Company's. The results and discussion regarding this comparative analysis is included in Section 6.9.

2.4 SUMMER & WINTER PEAK DEMAND & ANNUAL ENERGY

The 3-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 3-year actual and 15-year forecast.

2.5 ECONOMIC DEVELOPMENT RATES

As of March 1, 2018, the Company has six customer service locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 79 MW. As of March 1, 2018, the Company has no customers in North Carolina receiving service under economic development rates.

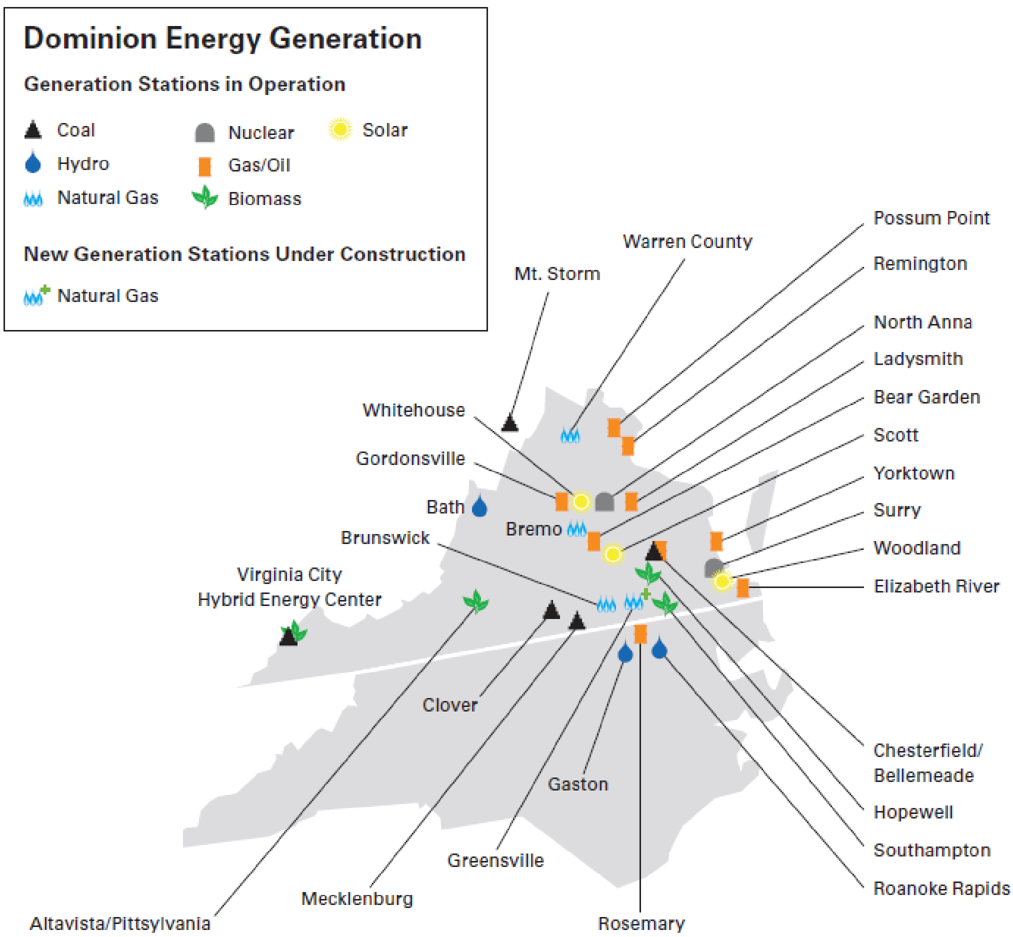
CHAPTER 3 – EXISTING AND PROPOSED RESOURCES

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 100 generation units includes 4 nuclear, 12 coal, 4 natural gas-steam, 10 CCs, 41 CTs, 4 biomass, 2 heavy oil, 6 pumped storage, 14 hydro, and 3 solar with a total summer capacity of approximately 18,265 MW.[13] The Company's continued operational goal is to manage this fleet in a manner that provides reliable, cost-effective service under varying conditions.

Figure 3.1.1.1 – Virginia Electric and Power Company Generation Resources



The largest proportion of the Company's generation resources has operated for 40 to 50 years, reflecting the major generation building program that met the needs of rapid population growth in the 1960s and 1970s, followed closely 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.

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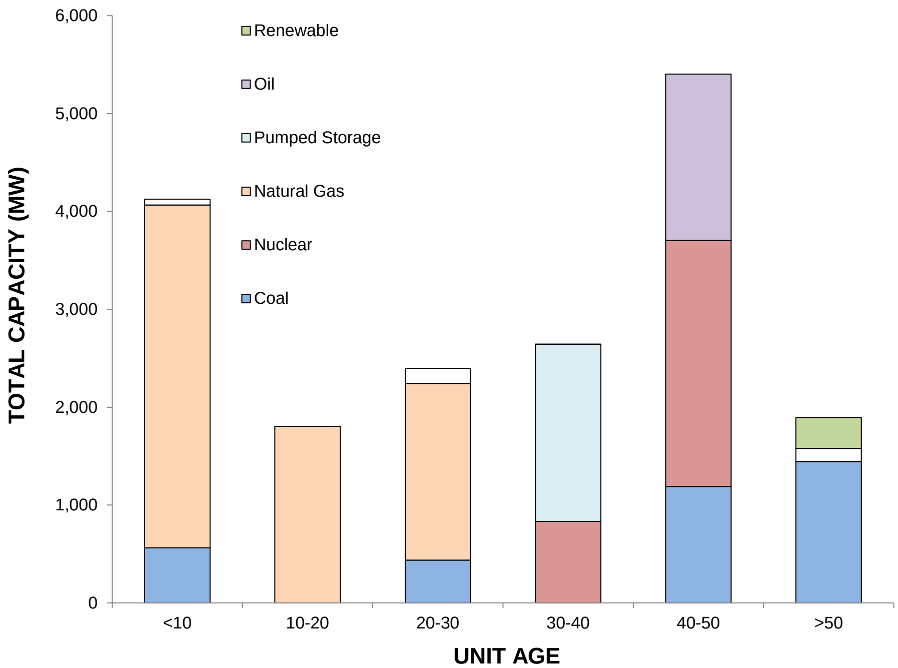
[13] All references to MW in Chapter 3 refer to summer nameplate capacity unless otherwise noted. Winter nameplate capacities for Company-owned units are listed in Appendix 3A.

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 905 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 2018 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 - 2018 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity[1] (MW)	Percentage (%)
Coal	3,638	19.5%
Nuclear	3,349	18.0%
Natural Gas	7,119	38.3%
Pumped Storage	1,808	9.7%
Oil	1,822	9.8%
Renewable	529	2.8%
NUG - Coal	218	1.2%
NUG - Natural Gas Turbine	0	0.0%
NUG - Solar	128	0.7%
NUG Contracted	**346**	**1.9%**
Company Owned	**18,265**	**98.1%**
Company Owned and NUG Contracted	**18,611**	**100.0%**
Purchases	**0**	**0.0%**
Total	**18,611**	**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 in 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 territories receive the benefit of 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 2017 actual capacity and energy mix.

Figure 3.1.1.4 - 2017 Actual Capacity Mix

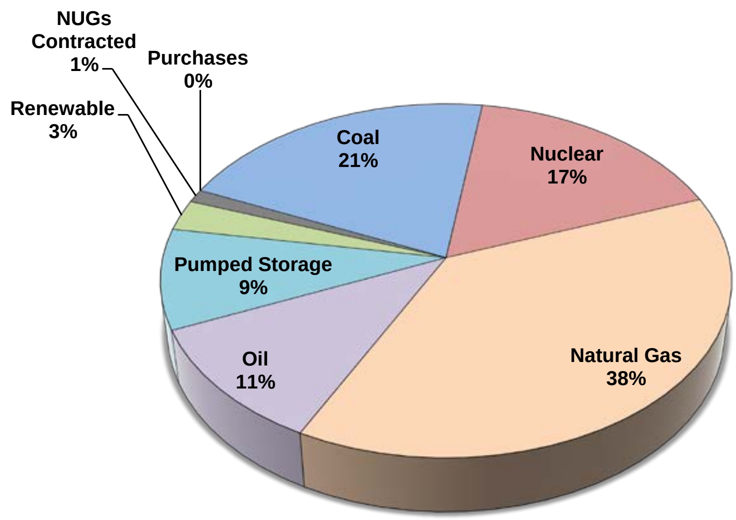
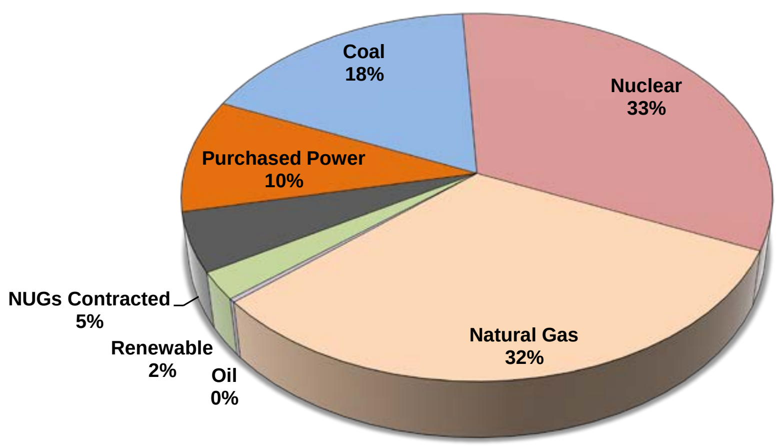


Figure 3.1.1.5 - 2017 Actual Energy Mix



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. Appendix 3F provides a summary of the existing capacity by fuel class and NUGs. Appendices 3G and 3H provide energy generation by type and by the system output mix. Appendix 3B provides a listing of other generation units including NUGs, BTMG, and customer-owned generation units.

3.1.2 EXISTING RENEWABLE RESOURCES

The Company currently owns and operates 533 MW of renewable resources, including approximately 8 MW (nameplate) of the solar generation facilities through the Solar Partnership Program and approximately 153 MW of biomass generating facilities, not counting Pittsylvania, which is currently planned to enter cold reserve in August. The Virginia City Hybrid Energy Center ("VCHEC") (610 MW) is expected to consume renewable biomass fuel of up to 7.5% (46 MW) in 2018 and gradually increase that level to 10% (61 MW) by 2023. The Company also owns and operates three hydro facilities: Gaston Hydro Station (220 MW), Roanoke Rapids Hydro Station (95

MW), and North Anna Hydro Station (1 MW). Additionally, the Company owns and operates three solar units totaling 56 MW (nameplate) in Virginia.

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 Programs	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
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
Schedule RF	X	-	X	-	-	X	X	≥ 30,000 MWh Annually of Incremental Load	None

Note: Eligibility and participation subject to individual program parameters.

Solar Partnership Program

The Solar Partnership Program is a demonstration program in which the Company is authorized to construct and operate up to 30 MW (direct current or “DC”) of Company-owned solar distributed generation (“DG”) facilities installed by the end of 2017 on leased commercial and industrial customer property and in community settings. This demonstration program allows the Company to study the benefits and impacts of solar DG on targeted distribution circuits. Current installed capacity of the program is 7.7 MW (nameplate). The Company does not currently have plans for additional installations under this program. More information can be found on the SCC website under Case No. PUE-2011-00117 and on the Company’s website: https://www.dominionenergy.com/large-business/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 its produced solar RECs. As of December 31, 2017, there were approximately 150 participants in the Solar Purchase Program with an installed capacity of 1.8 MW. More information can be found on the SCC website under Case No. PUE-2012-00064 and on the Company’s website: https://www.dominionenergy.com/home-and-small-business/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 RECs through the Company in discrete blocks for a portion or up to 100% of their usage. The Company purchases and retires RECs on behalf of participants. There are approximately 24,000 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.dominionenergy.com/home-and-small-business/ways-to-save/renewable-energy-programs/dominion-green-power.

Renewable Energy (Third-Party PPA) Pilot

The 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 are participating with a total installed capacity of approximately 1.2 MW. More information can be found on the SCC website under Case No. PUE-2013-00045 and on the Company's website: https://www.dominionenergy.com/large-business/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*.), as well as NCGS § 62-133.8(i)(6) and NCUC decisions issued in Docket No. E-100, Sub 83.[14] There are approximately 2,170 net metering customer-generators with a total installed capacity of approximately 17.4 MW. More information can be found on the Company's website: https://www.dominionenergy.com/home-and-small-business/ways-to-save/renewable-energy-programs/net-metering.

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.dominionenergy.com/home-and-small-business/ways-to-save/renewable-energy-programs/agricultural-net-metering.

Schedule RF

Schedule RF is an experimental and voluntary companion tariff that enables eligible customers to support the development of new renewable energy generation facilities by enhancing the cost effectiveness of such facilities. More information can be found on the SCC website under Case No. PUR-2017-00137.

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, along with any Virginia and North Carolina state level regulations (see Figure 3.1.3.3), 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 non-emitting nuclear, highly-efficient and clean-burning natural gas, solar, and hydro. The majority of the Company's coal-fired units are equipped with SO_2 and NO_x controls. The Company's coal-fired units at Chesterfield, Mt. Storm, Clover, Mecklenburg, and VCHEC have flue gas desulfurization environmental controls for SO_2 emissions. The Company's coal-fired generation at Chesterfield

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[14] North Carolina House Bill 589, signed into law on July 27, 2017, enacted NCGS § 62-126.4, which requires the Company and other utilities in North Carolina to file revised net metering rates for NCUC approval, but grandfathers existing net metering customers until 2027. No NCUC proceeding has yet been established to implement this directive.

(Units 4, 5, and 6), Mt. Storm, Clover, and VCHEC have selective catalytic reduction (“SCR”) or selective non-catalytic reduction (“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, Warren County, and Brunswick have SCRs. The remaining small coal-fired units are without sufficient emission controls to comply with anticipated regulatory requirements and are considered at risk units for purposes of this analysis.

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 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.

Bear Garden Power Station is a 2x1 CC that was completed in the summer of 2011. A turbine uprate was completed in May 2017, which increased the summer capacity to 622 MW, thereby adding 26 MW of additional highly-efficient and lower-emitting natural gas generation.

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

From 2000 through 2017, the Company has reduced the carbon intensity of its power generation fleet serving Virginia jurisdictional customers by 35% and its carbon emissions in tons by 26%, as shown in Figure 3.1.3.1. The carbon emission rate to meet the needs of customers, accounting for purchased power and non-utility generators, has also been reduced by 35% since 2000, as shown in Figure 3.1.3.2. The Company has reduced emissions through retiring certain at-risk units; building additional efficient and lower-emitting natural gas-fired power generating sources and carbon-free renewable energy sources, such as solar; and maintaining its existing fleet of non-emitting nuclear generation.

Figure 3.1.3.1 – Virginia Electric and Power Company CO_2 Reductions

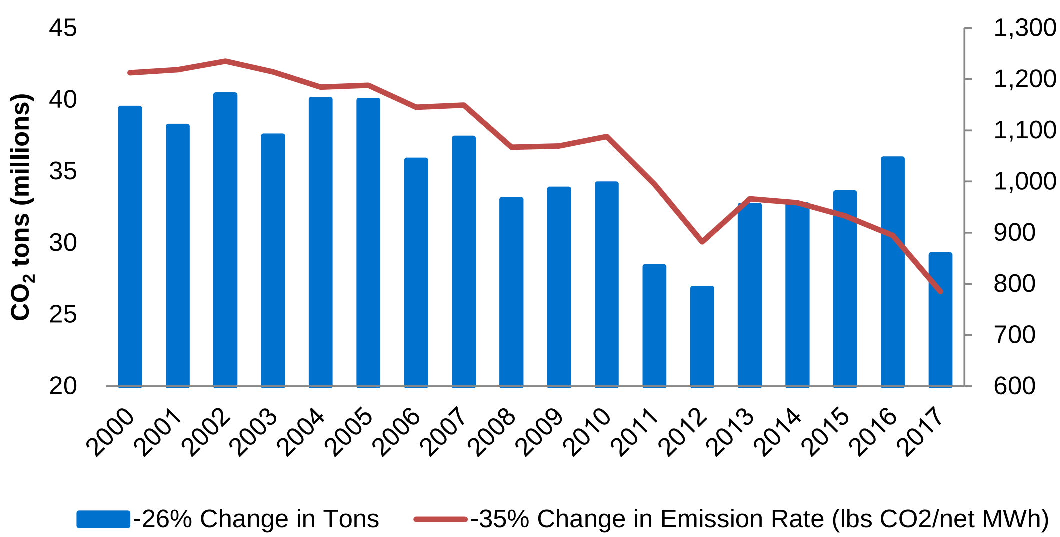
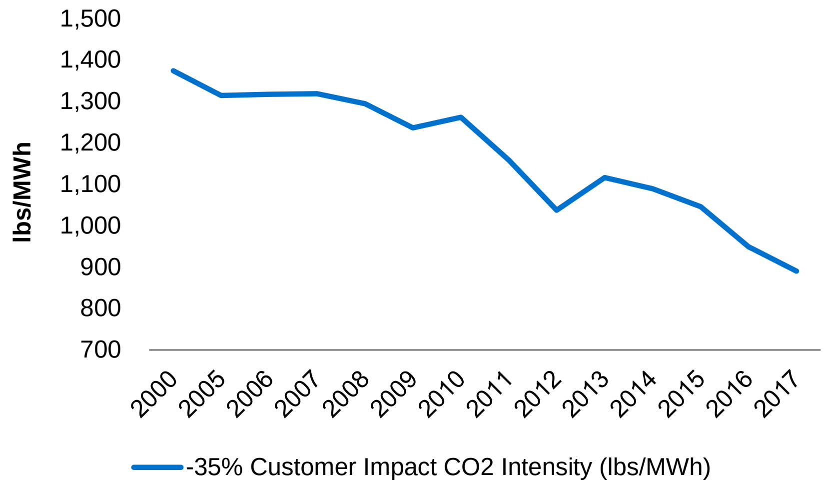


Figure 3.1.3.2 – Customer Impact CO_2 Reductions



EPA Regulations

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

Figure 3.1.3.3 - Environmental Regulations

Constituent		Key Regulation	Final Rule	Compliance Date	Notes
AIR	Hg/HAPS	Mercury & Air Toxics Standards (MATS)	12/16/2011	4/16/2017	Yorktown 1-2 ceased operation in April 2017. The DOE issued 90-day emergency order allowing operation when called upon by PJM in June 2017, September 2017, December 2017, and March 2018; PJM to seek rolling renewals as needed.
	SO_2	CSAPR	2011	2015 - 2017	SO_2 allowances decreased by 50% beginning in 2017. Retired units retain CSAPR allowances for four years. System is expected to have sufficient SO_2 allowances.
		SO_2 NAAQS	6/2/2010	2018	
	NOx	2008 Ozone Standard (75 ppb)	5/2012	2021	The Company is evaluating compliance options including SNCR and unit retirement.
		2015 Ozone Standard (70 ppb)	10/1/2015	2021	Expect compliance strategy for 2008 ozone NAAQS to meet requirements for 2015 ozone NAAQS.
		CSAPR	2011	2015 - 2017	Final revisions to CSAPR reduced ozone season NOx allowances reduced by approximately 22% beginning in 2017. Retired units retail CSAPR allowances for four years. System is expected to have sufficient annual NO_x allowances.
	CO_2	EGU NSPS (New)	10/2015	Retro to 1/8/2014	Rule under EPA review.
		EGU NSPS (Modified and Reconstructed)	10/2015	10/23/2015	Rule under EPA review.
		Clean Power Plan (CPP)	10/2015	Uncertain	Rule sets interim targets (2022-2024; 2025-2027; 2028-2029) in addition to 2030 targets. Rule also sets "equivalent" statewide rate-based and mass-based interim and 2030 targets. Rule currently stayed by Supreme Court. The EPA has proposed repeal of the rule.
		Virginia Carbon Regulations or RGGI	2018	2020 with glidepath to 2030	The DEQ under directive (ED-11) to propose by 12/31/17 a "trading ready" carbon reduction program to merge with exisitng multi-state carbon program. State issued draft proposal that links with RGGI program and includes RGGI's proposed 30% reduction from 2020 levels by 2030 and other allowance pool reduction mechanisms.
		Federal CO_2 Program (Alternative to CPP)	Uncertain	2026	
WASTE	ASH	Coal Combustion Residuals	4/17/2015	2023	Virginia has adopted the 2015 EPA coal combustion residuals rule. In March 2018, the EPA proposed amendments to the 2015 coal combustion residuals rule which remains in effect and unchanged until the proposed revisions become final. If the EPA 2018 revisions become final, the 2018 coal combustion residuals rule will apply to Mt. Storm; revisions will only apply in Virginia if state adopts revised rules. Compliance plans are being developed for 2015 coal combustion residuals. In addition, Virginia legislation requires evaluation of recycling options.
WATER	Water 316b	316(b) Impingement & Entrainment	5/19/2014	2016 - 2027	Rule does 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." 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.
	Water ELG	Effluent Limitation Guidelines	9/30/2015	2021 - 2022	Rule applies to coal units at 11 facilities. Rule does not apply to simple-cycle CTs or biomass units.
WILDLIFE	Threatened & Endangered	Atlantic Sturgeon Endangered Species Listing	1/2012	TBD	Incidental take permit is expected in Q2 2018 with details on compliance schedule, study scope and required mitigation.
		Atlantic Sturgeon Critical Habitat Listing	2017	2019 - 2023	Compliance dates are determined during the permit reissuance process and are expected to be as follows for each facility: Surry-2021, Chesterfield-2021, Yorktown-2023, Possum Point-2019.

Key: Constituent: Hg: Mercury; HAPS: Hazardous Air Pollutants; SO_2: Sulfur Dioxide; NO_x: Nitrogen Oxide; CO_2: Carbon Dioxide; Water 316b: Clean Water Act § 316(b) Cooling Water Intake Structures;
Regulation: MATS: Mercury & Air Toxics Standards; CPP: 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: Compliance assumed January 1 except where otherwise noted.

Revised Ozone National Ambient Air Quality Standards
In May 2008, the EPA revised the ozone National Ambient Air Quality Standard ("NAAQS") from 80 parts per billion ("ppb") to 75 ppb (the "2008 Ozone NAAQS"). In May 2012, the EPA designated the Northern Virginia area nonattainment for the 75-ppb standard which, coupled with the Northern Virginia area being part of the Northeast Ozone Transport Region, requires DEQ to evaluate reasonably available control technology ("RACT") requirements for major stationary sources of NO_x having the potential to emit of at least 100 tons per year, including the Possum Point facility, as part of its state implementation plan ("SIP"). In November 2016, the DEQ determined that the installation and operation of SNCR technology to control NO_x emissions on Possum Point Unit 5 is needed to meet RACT requirements under the 2008 Ozone NAAQS SIP. The Company is evaluating other alternatives including shutdown of this unit.

In October 2015, the EPA issued a final rule further tightening the ozone standard from 75 ppb to 70 ppb (the "2015 Ozone NAAQS"). States will have until 2021 to develop plans to address the new standard. The Company anticipates that the compliance strategy for Possum Point will also meet RACT requirements under the new 2015 Ozone NAAQS. At this time, no other power generating units are expected to be impacted by the new standard. In April 2017, the EPA verbally announced its intent to review its decision to tighten the standard from 75 to 70 ppb but, to date has not published an official notice initiating that review process. In the meantime, the EPA has begun implementing the 2015 Ozone NAAQS and is under a schedule to complete air quality designations for the new standard by April 2018.

Cross-State Air Pollution Rule/Ozone Transport
In October 2016, the EPA published final revisions to the Cross-State Air Pollution Rule ("CSAPR") that substantially reduced the CSAPR Phase II ozone season NO_x emission caps in 22 states, including Virginia and West Virginia, beginning with the 2017 ozone season. The reductions in state caps reduces the number of allowances the Company's EGUs will receive under the CSAPR Phase II ozone season NO_x program by 22% overall. In addition, the EPA will discount the use of banked Phase I allowances for compliance in Phase II by applying a surrender ratio that the EPA anticipates will be approximately 3.5:1. At this time, the Company does not anticipate the need for any additional NO_x controls to be installed on any units to meet these requirements.

In January 2017, the EPA issued a notice of data availability ("NODA") providing information on emission inventories, including EGUs. Additionally, the NODA provided air quality modeling projections that identified 18 eastern states, including several where the Company owns and operates electric generating facilities, as having a significant contribution to ozone nonattainment and/or interference with maintenance in another state. This information was provided to assist states in developing SIPs based on an evaluation of whether additional reductions in emissions of NO_x and/or volatile organic compounds beyond measures already in place or planned are needed to address interstate transport under the Clean Air Act's "good neighbor" provisions as it pertains to the 2015 Ozone NAAQS. Although the NODA itself does not do so, this information may be used by the EPA should the agency pursue a regional transport rulemaking requiring additional NO_x emission reductions from EGUs as a backstop to address ozone transport under the 2015 ozone NAAQS for states that fail to submit SIPs. At this time, the Company has not planned for any additional NO_x controls given the uncertainty of future regulatory action to further address ozone transport.

On March 12, 2018, the State of New York filed a petition with the EPA under Section 126 of the Clean Air Act ("CAA") alleging that certain stationary sources of NO_x emissions in nine states, including several EGUs in Virginia that are owned and operated by the Company, contribute to nonattainment in New York. The petition requests the EPA to impose strict NO_x limits equivalent to RACT requirements that New York has imposed on its facilities. The EPA has 60 days to act on Section 126 petitions, but has the authority under the CAA to extend the deadline. If the EPA grants the petition, it may grant affected sources up to three years to comply with the requirements imposed under a Section 126 remedy.

Coal Ash Regulations
In April 2015, the EPA's final rule regulating the management of coal ash stored in impoundments (ash ponds) and landfills was published in the Federal Register. This final rule regulates (i) coal ash landfills; (ii) existing ash ponds that still receive and manage coal ash; and (iii) inactive ash ponds that do not receive, but still store coal ash. The Company currently owns ash ponds and coal ash landfills subject to the coal ash 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 to perform required monitoring, corrective action, and post-closure care activities as necessary at both ponds and landfills. Virginia has adopted the current federal coal ash regulations into its state regulations. However, on March 15, 2018, the EPA published a proposed amendment to the federal coal ash regulations that included a number of revisions. The most significant proposed revision would allow risk-based groundwater remediation. Until the proposed amendment becomes final, the federal rule remains in effect and unchanged. The EPA is not seeking to suspend or cancel any part of the coal ash rule at this time. Additionally, until a facility is operating under a coal ash permit issued by a state with an EPA-approved program, the facility must continue to comply with the current federal coal ash rule and any applicable state rules. In Virginia, state regulations would have to be revised for any changes made to the federal rule to apply to Virginia locations. The Company is complying with all federal and state requirements.

In addition, a Virginia law, Senate Bill 1398, which came into effect on July 1, 2017, required that additional assessments be completed by the Company to evaluate alternatives for the closure of ash ponds at four locations (Bremo Bluff, Chesapeake, Chesterfield, and Possum Point Power Stations). These assessments included an evaluation of the feasibility of the excavation of the ponds and the recycling of ash from the ponds. Groundwater and surface water conditions were also evaluated in the assessments. Lastly, any corrective actions and safety aspects due to the closure of the coal ash ponds were evaluated. The Company engaged a third party to complete the assessment. The report was completed and submitted to the DEQ on December 1, 2017.[15]

The assessment concluded that all of the options would be fully protective of safety, human health, and the environment. All options would meet the state and federal requirements. The range in costs for the closure options is significant—a difference of more than $7.38 billion from the lowest to the highest for the sites. Some alternatives could take longer to complete than allowed by federal regulation.

The impact on the local communities also can vary based on the closure options employed. It is premature to predict with certainty the expenses and other costs associated with the closing, corrective action, and ongoing monitoring of ash ponds.

In addition, as the state and federal coal ash rule is implemented, the rule provides for a number of requirements including groundwater monitoring for both ash ponds and landfills. The first annual groundwater report was posted for active coal ash ponds on March 2, 2018. Additional monitoring will be needed to determine whether corrective action is required at ash ponds or landfills. Groundwater monitoring will continue for 30 years after a coal ash pond or landfill is closed.

In the 2018 Regular Session, Senate Bill 807 was passed by the General Assembly and was approved by the Governor on March 30, 2018. The Bill provides that permit applications for ponds where ash is being or has been removed can be considered by the DEQ. For Bremo north pond, Chesterfield lower and upper ponds, Chesapeake landfill and bottom ash ponds and Possum Point

[15] See https://www.dominionenergy.com/coalash.

D pond, a request for proposal for recycling ash from these locations is to be issued by the Company to provide additional information on options for closure. A report on the options identified is to be provided to the General Assembly committees, the DEQ, and the Virginia Department of Conservation and Recreation by November 15, 2018.

Clean Water Act, Cooling Water Intake Regulations
In October 2014, final regulations became effective under Section 316(b) of the Clean Water Act, which govern existing facilities that employ a cooling water intake structure and have flow levels exceeding a minimum threshold. The rule established a national standard for impingement based on seven compliance options. The EPA has delegated entrainment technology decisions to state environmental regulators. State environmental regulators will 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 are subject to these regulations, and anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. The Company is evaluating the need and/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 beginning in 2018, and will be installed in accordance with schedules established in those permits. The costs for these additional control technologies could be significant.

Four of the facilities subject to these regulations have generating units that the Company is transitioning to cold reserve status. The Company is working with the DEQ to determine how cold reserve will impact Section 316(b) compliance requirements.

Clean Power Plan
As discussed in Chapter 1, the Company no longer believes the CPP to be a "pending" regulation. However, based on a broad interpretation of the SCC's directive in its 2017 Plan Final Order that the Company's future plans comply with the requirement of Va. Code § 56-599 B 9 (requiring the IRP to include "the most cost effective means of complying with current and pending state and federal environmental regulations" the Company provides a build plan under a CPP scenario and the resulting NPV. See Appendix 1B. The Company also notes that RGGI is more restrictive than the originally proposed CPP and that it is possible that future federal regulations could also be more stringent. The Company assesses a plausible future path complying with Virginia RGGI or RGGI in Alternative Plans B, C, and D.

3.1.3.1 POTENTIAL STATE CARBON REGULATION
The Company has closely monitored and actively participated in the process the Commonwealth of Virginia has undertaken to address power sector GHG emissions. As discussed in Chapter 1, the Commonwealth has attempted to address GHG emissions through both legislative and executive action. The General Assembly has considered legislation requiring Virginia to join RGGI, but such legislation has failed to date. While Virginia appears to be moving forward with carbon regulations through executive action (i.e., the Virginia RGGI Program), the 2018 Plan considers both RGGI and the Virginia RGGI Program.

RGGI
Initiated in 2009, RGGI is a collaborative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO_2 emissions from the power sector. New Jersey, an original participant in RGGI, withdrew from the program in 2013, but has recently announced that it will initiate a process to rejoin the program. According to the RGGI website:

> RGGI is composed of individual CO_2 Budget Trading Programs in each participating state. Through independent regulations, based on the RGGI Model Rule, each state's CO_2 Budget Trading Program limits emissions of CO_2 from electric power plants, issues CO_2 allowances and establishes participation in regional CO_2 allowance auctions. RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States. Within the RGGI states, fossil-fuel-fired electric power generators with a capacity of 25 megawatts (MW) or greater ("regulated sources") are required to hold allowances equal to their CO_2 emissions over a three-year control period. A CO_2 allowance represents a limited authorization to emit one short ton of CO_2 from a regulated source, as issued by a participating state. Regulated power plants can use a CO_2 allowance issued by any participating state to demonstrate compliance in any state. They may acquire allowances by purchasing them at regional auctions, or through secondary markets.[16]

Historical and future RGGI regional cap levels for allowances per year are as follows:

- 2009 - 2011: RGGI cap was 188 million tons per year for the RGGI region (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont);
- 2012 - 2013: RGGI cap was reduced to 165 million tons per year (to account for New Jersey's withdrawl from the program);
- 2014: RGGI cap was 91,000,000, RGGI adjusted cap was 82,792,336;[17]
- 2015: RGGI cap was 88,725,000, RGGI adjusted cap was 66,833,592;
- 2016: RGGI cap was 86,506,875, RGGI adjusted cap was 64,615,467;
- 2017: RGGI cap was 84,344,203, RGGI adjusted cap was 62,452,795;
- 2018: RGGI cap is 82,235,598, RGGI adjusted cap is 60,344,190;
- 2019: RGGI cap is 80,179,708, RGGI adjusted cap is 58,288,301;
- 2020: RGGI cap is 78,175,215, RGGI adjusted cap is 56,283,807;
- 2021 - 2030: A regional cap of 75,147,784 tons of CO_2 in 2021, which will decline by 2.275 million tons of CO_2 per year thereafter. The RGGI states will address the bank of allowances held by market participants with an adjustment for banked allowances. This adjustment will be made over a 5-year period (2021 - 2025) based upon the size of the bank at the end of 2020.

All adjusted cap figures identified above represent RGGI program adjustments based on the allowance bank at the close of a predetermined period of time.

There is no ceiling price for RGGI allowances. However, RGGI has established a cost containment reserve ("CCR"), consisting of a quantity of allowances in addition to the cap that are held in reserve:

[16] https://www.rggi.org/program-overview-and-design/elements.
[17] RGGI implemented adjustments reducing the regional cap to account for banked allowances beginning with the 2014 control period.

> These [reserve allowances] are only made available for sale if allowance prices exceed predefined price levels, so that the CCR will only trigger if emission reduction costs are higher than projected. The CCR is replenished at the start of each calendar year. The CCR trigger price [which is currently $10.25/ton of CO_2] will increase by 2.5% per year through 2020, and its size will be 10 million allowances each year. Then, based on the 2017 Model Rule, after 2020 the CCR size and trigger price trajectory will change. The CCR trigger price will be $13.00 in 2021 and will increase by 7% per year thereafter. The CCR's size will be 10% of the regional cap each year.[18]

There is also no floor price for RGGI allowances, although RGGI plans on introducing an emissions containment reserve ("ECR") beginning in 2021:

States implementing the ECR will withhold allowances from circulation to secure additional emissions reductions if prices fall below established trigger prices, so that the ECR will only trigger if emission reduction costs are lower than projected. The ECR trigger price will be $6.00 in 2021, and rise at 7% per year thereafter. Its size will be 10% of the budgets of the states implementing the ECR. (Note that at this time, Maine and New Hampshire do not intend to participate in the ECR).[16]

RGGI allowances are obtained by participants through quarterly, regional CO_2 allowance auctions. These auctions are sealed-bid, uniform price auctions that are open to all qualified participants, which can include non-compliance entities. They result in a single quarterly clearing price. In most RGGI states, auction revenue is returned to state coffers. In addition to purchasing allowances at auction, entities are also able to trade allowances on secondary markets, via over-the-counter trades or exchanges.

The Virginia General Assembly has considered legislation to join RGGI. To date, these legislative efforts have not been successful, though the executive branch in Virginia is pursuing a similar administrative regulation.

Virginia RGGI

Apart from the legislative process, Virginia has taken action to address the power sector GHG emissions through a series of executive actions and directives.

On May 16, 2017, then Governor McAuliffe issued ED-11, which requires the DEQ to:

> 1. Develop a proposed regulation for the State Air Pollution Control Board's consideration to abate, control, or limit carbon dioxide emissions from electric power facilities that:
>
> a. Includes provisions to ensure that Virginia's regulation is "trading-ready" to allow for the use of market-based mechanisms and the trading of carbon dioxide allowances through a multi-state trading program; and

[18] https://www.rggi.org/program-overview-and-design/elements.

b. Establishes abatement mechanisms providing for a corresponding level of stringency to limits on carbon dioxide emissions imposed in other states with such limits.

2. By no later than December 31, 2017, present the proposed regulation to the State Air Pollution Control Board for consideration for approval for public comment in accordance with the Board's authority. [19]

In accordance with ED-11, the DEQ developed a draft regulation establishing a cap-and-trade program in Virginia with the intent to link the program to RGGI. The draft proposal seeks to facilitate a linkage to RGGI by including most of the elements of the RGGI 2017 Model Rule which was finalized in December 2017. The DEQ proposal requires sources covered under the program to consign allocated emission allowances to the RGGI allowance auction. Under this approach, the allowance revenue collected via the RGGI allowance auctions would be allocated to covered generation sources in Virginia.

The Virginia State Air Pollution Control Board ("VSAPCB") and then Governor McAuliffe approved the DEQ draft proposal on November 16, 2017, and December 15, 2017, respectively. The draft proposal (referred to in this 2018 Plan as the Virginia RGGI Program) and notice seeking public comments were published in the *Virginia Register* on January 8, 2018, which initiated a 90-day comment period on the proposed regulation effective through April 9, 2018. The DEQ expects to finalize the rule by late 2018.

If finalized as currently proposed, CO_2 allowance allocation budgets would begin under the Virginia RGGI Program in calendar year 2020. The Virginia RGGI Program would cap CO_2 emissions for Virginia at 33 or 34 million tons for calendar year 2020, and would decrease the emissions cap annually by approximately 3% to achieve a 30% reduction from 2020 levels to a level of 23.1 million tons or 23.8 million tons in 2030. Emission sources subject to the Virginia RGGI Program would be required to obtain and surrender a CO_2 emission allowance for every ton of CO_2 emitted during a control period through participation in a consignment auction linked to the RGGI allowance auction program.

A unique feature of the proposed Virginia RGGI Program calls for CO_2 allowances to be allocated (at no charge) to Virginia generators, apportioned based on each unit's pro rata share of the statewide historical generation output (in MWh). Specifically, the DEQ proposes to link the Virginia RGGI Program to RGGI by way of a consignment auction. Under this approach, the DEQ would allocate a pool of allowances, called conditional allowances, to each generating unit. These conditional allowances would need to be consigned over to the RGGI auction and clear the RGGI market in order to be converted to conventional allowances that can be used for compliance purposes. Revenue generated through the sale of the allowances in the RGGI auction (based on the auction clearing price) would be returned to the generators.

According to the DEQ, the purpose of the consignment auction is to ensure that the Virginia RGGI Program allowances enter the RGGI market and that the auction proceeds are collected and redistributed directly to the generators.

Evaluation of RGGI and Virginia RGGI

On April 9, 2018, the Company submitted written comments to the DEQ on its proposal to regulate carbon emissions from Virginia power plants. In the comments, the Company noted that the

[19] http://register.dls.virginia.gov/details.aspx?id=6770.

Commonwealth's linkage to the RGGI program through the Virginia RGGI Program would encourage electricity imports from out-of-state sources that are more carbon-intensive with no real mitigation of GHG emissions regionally and would result in a financial burden on Virginia electricity customers.

Modeling requested by the Company, as discussed in more detail below, supports these concerns. In summary:

- Virginia's linkage to RGGI will encourage electricity imports from out-of-state sources that are more carbon intensive. The program will result in a significant increase in power imports while highly-efficient and lower-emitting NGCC facilities in Virginia will run less;
- Reductions in carbon emissions in Virginia, as a result of the increased use of imported power, will be offset by emission increases elsewhere within the NERC EI, which includes all of PJM and the RGGI region;
- Increased imports of more carbon-intensive power will result in the carbon footprint per customer in Virginia increasing by about 5.7% by 2030; and
- Linking to RGGI could impose over $500 million in additional cost to Virginia customers during the 2020 to 2030 period.

The renewable generation encouraged by the GTSA, if approved and constructed, will, to some degree, mitigate power imports and costs.

If Virginia joins RGGI, Virginia generators would need to account for the price (i.e., value) of RGGI CO_2 allowances in its cost of dispatch, much like federal SO_2 and NO_x programs. Unlike those federal programs, however, generators in neighboring states that are not subject to RGGI or a similar state-level program would have no such cost. Thus, generators in Virginia would be at a cost disadvantage to generators in neighboring states not subject to RGGI, such as North Carolina and West Virginia. This would lead to higher levels of more carbon intensive imported power into Virginia and could lead to stranded assets in Virginia. Electric customers in Virginia would be subject to the volatile price swings of the imported power markets while still paying for in-state generation assets in Virginia that are utilized less than planned. It should be noted that most RGGI states no longer have vertically integrated utilities. Moreover, among the 13-state PJM regional transmission organization that the Company belongs to, most states are not RGGI participants, even assuming that both New Jersey and Virginia join. Virginia also has competitive shopping provisions for large customers that are atypical for vertically integrated regulatory models. These factors all heighten the potential for customers to bypass costs associated with RGGI (and potentially other environmental costs such as coal ash management) by competitively shopping.

While CO_2 emissions in Virginia would decrease under RGGI as a result of imported power, there would be no change in overall CO_2 emissions on a regional basis because most of the imported power would be sourced from more carbon intensive natural gas- or coal-fired generation. While the Company is committed to a lower carbon future, it believes, based on careful analysis, that the Commonwealth's participation in RGGI would penalize Virginia generators relative to those in other states and result in cost increases for Virginia electricity customers with no real mitigation of GHG emissions.

An additional consideration is the potential likelihood that Virginia's emissions cap under the RGGI program will be lowered. RGGI re-assesses its program every three years based on historical performance. Since 2009, RGGI has conducted two program reviews, one in 2012 and one in 2017. Both of these reviews have resulted in a lowering of going-forward CO_2 emission caps for the RGGI region. The next assessment period is scheduled to occur in 2021, which is only one year after Virginia would begin its participation in RGGI under the Virginia RGGI Program. This means that the Virginia cap identified in the current Virginia RGGI Program through 2030 may be re-negotiated in 2021 and may be different than what is currently proposed. Effectively, Virginia's entrance into

RGGI through the Virginia RGGI Program creates just two years (i.e., 2020 and 2021) of known CO_2 limitations. Based on RGGI's two prior re-assessments, the CO_2 cap will likely be different than what is currently proposed. This periodic re-assessment increases uncertainty in electric utility planning.

From the Company's perspective, any program setting carbon emission targets for EGUs must account for the dynamics of power generated outside of and imported into Virginia. The program baseline and targets must reflect and account for the fact that Virginia is a net importer of energy from more carbon-intensive out-of-state resources. The program also must be designed to allow for expansion of lower-emitting cleaner generation in the state to address energy needs and to reduce imports of electricity in accordance with state energy policy. Encouraging the expansion of highly-efficient NGCC and renewable energy resources, including solar, wind, and pumped storage, within the Commonwealth will grow the state's economy and lower emissions by decreasing reliance on more carbon-intensive power imported from other states.

Further, Virginia's carbon footprint from electric power generation is already significantly cleaner than many of its neighboring states. The Company is concerned that setting a stringent cap on already cleaner generation in Virginia absent a similar level of reductions from neighboring states would increase the cost burden to Virginia generators. Such a cap would likely encourage lower cost electricity imports from out-of-state sources that are more carbon-intensive and not subject to a carbon cost adder. This could result in the unintended consequence of curtailing or limiting the dispatch of highly-efficient and lower-emitting generating facilities in Virginia and encouraging the dispatch of higher-emitting resources in neighboring states.

With federal regulations currently stayed and under administrative review, few states outside of the northeast RGGI program and along the west coast have proceeded or are proceeding with definitive carbon regulations. This includes the majority of PJM member states including Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, and the District of Columbia. Coupled with the possible forced retirement and/or curtailment of fossil fuel-fired resources, this raises reliability concerns with increased dependence on more carbon intensive out-of-state power to meet Virginia's energy needs.

These concerns are borne out by comparing the results of the No CO_2 Tax commodity forecast to the Virginia RGGI commodity forecast—forecasts that were requested by the Company and performed by ICF.[20] In support of the 2018 Plan, ICF provided the Company with forecasts for a case where Virginia joins RGGI (Virginia RGGI) and a case where Virginia does not join RGGI (No CO_2 Tax). Both cases assume no CO_2 program at the federal level. Further, both cases assume that New Jersey rejoins and participates in RGGI beginning in 2020. Although the Virginia RGGI regulation would not involve Virginia directly "joining" RGGI, the rule as proposed is designed to link to the RGGI program by way of a consignment auction of CO_2 emission allowances, a level and timeline of emission reductions equivalent in stringency to RGGI, and provisions implementing the RGGI 2017 Model Rule. The region modeled covers the U.S. and Canada, including the entire NERC EI.

The analysis shows that the Virginia RGGI Program does not result in overall carbon emission reductions in the EI or PJM regions by 2030. Under the analysis, emissions in the entire EI in 2030 are about 10 million tons higher than emissions in 2020, and about 3 million tons higher in the PJM region during the same period. The analysis shows that, for the most part, emissions reductions achieved in the RGGI region would be offset by emissions increases in the non-RGGI portions of the region. Cumulatively, over the period 2020 to 2030, emissions in the portion of the EI subject to

[20] See Section 4.4.2 for discussion of the alternative commodity forecasts. These sensitivity cases do not represent ICF's reference case view.

RGGI would be reduced by about 75 million tons, but would increase by almost 90 million tons in the non-RGGI portion of the EI. In PJM, the total emission levels in 2030 in the case where Virginia joins RGGI are only one half of one percent lower (2 million tons) than in the case where Virginia does not join RGGI.

The analysis also shows significant increases in net energy imports (gigawatt hours "GWh") in Virginia (based on annual retail sales of electricity) with Virginia linked to RGGI, almost doubling from about 28% under the case with no carbon regulations in Virginia to 48% for the case with Virginia joining RGGI. At the same time, the weighted average capacity factor for NGCC facilities in Virginia is projected to decrease by almost 50% between 2020 and 2030 under the RGGI case. Natural gas-fired units in Virginia will still be subject to a CO_2 cost adder that units outside of the carbon-constrained region will not be subject to. Thus, the effect of RGGI-equivalent reduction requirements in Virginia is likely to limit the dispatch of highly-efficient and lower-emitting NGCC facilities in Virginia and to encourage the dispatch of higher-emitting resources and increased emissions in neighboring states outside of the RGGI region.

The modeling results also show that the average carbon intensity in 2030 of electricity (imports and in state generation) in Virginia with the state not joining RGGI is projected to be 742 lbs/MWh in 2030. Carbon intensity increases to 784 lbs/MWh if Virginia joins RGGI. This is a 5.7% *increase* in carbon intensity of the electricity used by Virginia customers, largely due to increased electricity imports into Virginia, which have a higher carbon intensity than in-state generation.

Analysis of the modeling results also reflects that linking to RGGI is projected to cost Virginia customers about $530 million over the period 2020 to 2030. This includes cost for carbon emission allowances plus increased imported power cost adjusted for reduction in total production cost for Virginia. Furthermore, the modeling indicates that Virginia joining or linking to RGGI will lower allowance prices, thereby lowering the cost of carbon compliance in other RGGI states subsidized, in part, by Virginia electricity customers. Should Virginia join or link to RGGI, the RGGI states outside of Virginia will incur $876 million less in costs related to RGGI allowance purchases for the period 2020 to 2030 than the RGGI states would have incurred without Virginia joining RGGI.

3.1.4 GENERATION RETIREMENTS & BLACKSTART

Retirements

Based on the current and anticipated environmental regulations along with current market conditions, the 2018 Plan includes the following impacts to the Company's existing generating resources in terms of retirements. On April 16, 2016, the EPA granted permission, through an Administrative Order, to operate the Yorktown Units 1 (159 MW) and 2 (164 MW), until April 15, 2017, under certain limitations consistent with the Mercury and Air Toxic Standards ("MATS"). Upon expiration of the EPA Administrative Order on April 15, 2017, the Company ceased operation of the Yorktown coal-fired units to comply with MATS. On June 13, 2017, PJM filed a request for emergency order pursuant to Section 202(c) of the Federal Power Act[21] with the U.S. Department of Energy ("DOE"), and on June 16, 2017, the DOE granted an order ("DOE Order") to PJM to direct the Company to operate Yorktown Units 1 and 2 as needed to avoid reliability issues on the Virginia Peninsula for 90 days. In response to subsequent PJM requests for renewals of the DOE Order, the DOE issued additional 90-day emergency orders pursuant to Section 202(c) of the Federal Power Act on September 14, 2017, December 13, 2017, and March 13, 2018. PJM plans to request further renewals of the emergency orders on a rolling basis until the Skiffes Creek electric transmission project in the Peninsula region is placed into service. While this is not a long-term solution to the reliability issues in the Virginia Peninsula, the Company supports PJM's action and the DOE decision, and will work to ensure the units' availability as required.

[21] See generally 16 U.S.C. § 824.

For purposes of this 2018 Plan, the Company made certain assumptions regarding generation unit retirements. The generators listed below should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date. For purposes of this 2018 Plan, the assumptions regarding generation unit retirements are as follows:

- Bellemeade (267 MW) to be potentially retired by 2021 in all Alternative Plans;
- Bremo Power Units 3 and 4 (227 MW) to be potentially retired by 2021 in all Alternative Plans;
- Chesterfield Units 3 and 4 (261 MW) to be potentially retired by 2021 in all Alternative Plans;
- Mecklenburg Units 1 and 2 (138 MW) to be potentially retired by 2021 in all Alternative Plans;
- Pittsylvania (83 MW) to be potentially retired by 2021 in all Alternative Plans;
- Possum Point Units 3 and 4 (316 MW) to be potentially retired by 2021 in all Alternative Plans;
- Possum Point Unit 5 (786 MW) to be potentially retired by 2021 in all Alternative Plans;
- Yorktown Unit 3 (790 MW) to be potentially retired by 2022 in all Alternative Plans;
- Chesterfield Units 5 (336 MW) and 6 (670 MW) to be potentially retired by 2023 in Alternative Plans B, C, and D; and
- Clover Units 1 (220 MW) and 2 (219 MW) to be potentially retired by 2025 in Alternative Plans B, C, and D.

Figure 6.9.1 reflects the results of a retirement and co-fire analysis that was conducted by the Company regarding the Company's coal- and heavy-oil fired units. This analysis is included in this 2018 Plan as a result of a request by the SCC Staff during the 2016 Plan regulatory proceedings.

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. NERC Reliability Standard EOP-005-2 requires each 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 a transmission owner. The Company and other PJM members have and continue to work with PJM to implement an RTO-wide strategy for procuring blackstart resources. This strategy ensures a resilient and robust system capable of meeting blackstart and restoration requirements. The strategy is described in detail in Section 10 of PJM Manual 14D – Generator Operational Requirements.[22] PJM issues an RTO-wide request for proposal ("RFP") for blackstart generation every five years, which is 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. The third solution for 151 MW became effective on June 1, 2016. PJM issued an RTO-wide RFP in January 2018. The blackstart solutions must be implemented by April 1, 2020. For incremental changes in resource needs or availability that may arise between the five-year solicitations, the strategy includes an incremental RFP process.

[22] See http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

3.1.5 GENERATION UNDER CONSTRUCTION

The SCC approved a certificate of public convenience and necessity ("CPCN") for Greensville County Power Station (1,585 MW CC) on March 29, 2016. The unit is currently under construction and is expected to be online by 2019.

Figure 3.1.5.1 and Appendix 3K provide a summary of the generation under construction included in the Alternative Plans 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
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 requirement is supplemented with contracted NUGs. The Company has existing contracts with fossil-burning and renewable NUGs and BTMG for capacity of approximately 905 MW (nameplate). These NUGs are all considered firm generating capacity resources and are included in the 2018 Plan as supply-side resources.

Each of the NUGs listed as a capacity resource in Appendix 3B, including solar NUGs, are 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 Company's 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 or -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.

3.1.7 WHOLESALE & PURCHASED POWER

Wholesale Power Sales

The Company currently provides full requirement 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 requirement 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 to whom the Company has either committed, or expects to sell power during the Planning Period.

Purchased Power

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 satisfied its capacity obligation from the RPM auction through May 31, 2021.

Behind-the-Meter Generation

BTMG occurs on the customer’s side of the meter. Typically, 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.

3.2 DEMAND-SIDE RESOURCES

In 2007, the Commonwealth of Virginia set a public policy goal of reducing the consumption of electric energy by retail customers by 10% from its 2006 baseline by 2022. The Company expressed its commitment to helping Virginia reach this goal through the implementation of cost-effective DSM programs.

In 2018, the Commonwealth reiterated its commitment to energy conservation in the GTSA. Specifically, an enactment clause of the GTSA requires the Company to develop proposed programs of energy conservation measures with a projected cost of no less than $870 million for the period beginning July 1, 2018, and ending July 1, 2028. At least 5% of the proposed programs must benefit low-income, elderly, and disabled individuals. In developing these programs, the Company must utilize a stakeholder process to receive input and feedback on the development of its energy efficiency programs. The stakeholder process will be facilitated by an independent monitor compensated under the funding provided pursuant to Va. Code § 56-592.1 E, and will include representatives from the SCC, the Attorney General’s Office of Consumer Counsel, the Department of Mines, Minerals and Energy, energy efficiency program implementers, energy efficiency providers, residential and small business customers, and any other interested stakeholders who the independent monitor deems appropriate for inclusion.

The Company generally defines DSM as all activities or programs undertaken to influence the amount and timing of electricity use. DSM encourages the more efficient use of existing resources and delays or eliminates 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 2018 Plan, four categories of DSM programs are addressed: (i) those approved by the SCC and NCUC; (ii) those filed with the SCC for a program extension; (iii) those under consideration but that have not been fully evaluated (i.e., potential DSM resources); and (iv) those currently rejected from further consideration. The Company’s programs have been designed and evaluated using a system-level analysis. Figure 3.2.1 provides a tabular representation of the approved, proposed extension, under consideration, and rejected programs.

Figure 3.2.1 - DSM Tariffs & Programs

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

3.2.1 DSM PROGRAM DEFINITIONS

For purposes of its DSM programs in Virginia, the Company applies the 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 shall be 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 interconnection 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 non-renewable 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. 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 2017 Plan.

STANDBY GENERATION

Program Type: Energy Efficiency - Demand Response
Target Class: Commercial & Industrial
Participants: 2 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, to enrolled customers 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 the 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 provides estimated load response data for summer/winter 2017. Additional jurisdictional rate schedule information is available on the Company's website at www.dominionenergy.com.

Figure 3.2.2.1 - Estimated Load Response Data

	Summer 2017		Winter 2017	
Tariff	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	19	1.5	1	0.5

3.2.3 CURRENT & COMPLETED DSM PILOTS & DEMONSTRATIONS

Pilots

The Company has received SCC approval for implementation of the DSM pilots described below.

Dynamic Pricing Tariffs Pilot

State: Virginia
Target Class: Residential and Non-Residential
Pilot Type: Peak-Shaving
Pilot Duration: Pilot concluded July 31, 2017

Description:

On September 30, 2010, the Company filed with the SCC an application (Case No. PUE-2010-00135) requesting approval of three experimental and voluntary dynamic pricing tariffs designated Rate Schedules DP-R, DP-1, and DP-2 ("Dynamic Pricing Tariffs"), as part of a structured comprehensive pilot program that the Company would implement in its Virginia service territory ("Dynamic Pricing Pilot"). The Dynamic Pricing Pilot program was approved by the SCC's Order Establishing Pilot Program issued on April 8, 2011.

The Dynamic Pricing Pilot was branded as the Company's Smart Pricing Plan, and the Dynamic Pricing Tariffs were open for eligible customers to take service beginning July 1, 2011. The Dynamic Pricing Tariffs were approved for extension and expansion in August 2013. New customer enrollment ended on November 30, 2014. The Pilot was approved for extension a second time on December 18, 2015 and ended as scheduled on July 31, 2017. On June 1, 2017, the SCC approved the Company's request to allow pilot participants to remain on the Dynamic Pricing Tariffs after the July 31, 2017 pilot conclusion date if they so chose.

Status:
The Company does not plan to offer the Dynamic Pricing Pilot as designed to additional customers on a larger scale. The Company will continue to evaluate options for customers to manage their energy use, including dynamic pricing, similar rate offerings, and demand side management programs, and the results from the Dynamic Pricing Pilot will be an important input into those evaluations going forward. Additional information is available in the Company's Annual Report on the Dynamic Pricing Pilot filed on October 31, 2017, in Case No. PUE-2010-00135.

Electric Vehicle Pilot

State:	Virginia
Target Class:	Residential
Pilot Type:	Peak-Shaving
Pilot Duration:	Enrollment began October 3, 2011, and concluded September 1, 2016 Pilot scheduled to conclude November 30, 2018.

Description:
On January 31, 2011, the Company filed an application with the SCC (Case No. PUE-2011-00014) proposing a pilot program to offer experimental and voluntary electric vehicle ("EV") rate options to encourage residential customers who purchase or lease EVs to charge them during off-peak periods. The SCC approved the pilot in July 2011. The pilot program provided two rate options. One rate option, a "whole house" rate, allowed customers to apply the time-of-use rate to their entire service, including their premises and vehicle. The other rate option, an "EV only" rate, allowed customers to remain on the existing residential rate for their premises and subscribe to the time-of-use rate only for their vehicle. The program was limited to 1,500 residential customers, with up to 750 in each of the two experimental rates. Additional information regarding the Company's EV Pilot Program is available in the Company's application, in the SCC's Order Granting Approval, in the Company's Annual Reports, and at https://www.dominionenergy.com/electricvehicle.

Status:
As of December 31, 2017, there were 409 customers enrolled on the whole-house EV rate and 158 customers were enrolled on the EV-only rate.

AMI Upgrades

State:	Virginia and North Carolina
Target Class:	All Classes
Type:	Energy Efficiency
Duration:	Ongoing

Description:
The Company continues to upgrade meters to advanced metering infrastructure ("AMI" or "smart meters").

Status:
As of December 2017, the Company has installed over 385,000 smart meters in areas throughout Virginia and North Carolina. The AMI meter upgrades are part of an ongoing project that will help the Company further evaluate the effectiveness of AMI meters in: achieving voltage conservation and voltage stability; remotely turning off and on electric service; detecting and reporting power outages; remotely integrating DERs; and offering dynamic rates. AMI is critical for grid modernization as discussed in Section 5.1.4.

3.2.4 CURRENT CONSUMER EDUCATION PROGRAMS

The Company's consumer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption. The Company's website has a section dedicated to energy conservation that contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Through consumer education, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina. Examples of how the Company seeks to increase customer awareness include:

Customer Connection Newsletter
State: Virginia and North Carolina
The Customer Connection Newsletter contains news on topics such as DSM programs, how to save money and manage electric bills, helping the environment, service issues, and safety recommendations, in addition to many other relevant subjects. Articles from the most recent Customer Connection Newsletter are located on the Company's website at: https://www.dominionenergy.com/community/customer-newsletters.

Twitter® and Facebook®
State: Virginia and North Carolina
The Company uses the social media channels of Twitter® and Facebook® to provide real-time updates on energy-related topics, promote Company messages, and provide two-way communication with customers. The Company's Twitter® account is available online at: www.twitter.com/DomEnergyVA. The Company's Facebook® account is available online at: https://www.facebook.com/dominionenergyva.

News Releases
State: Virginia and North Carolina
The Company prepares news releases and reports on the latest developments regarding its DSM initiatives and provides updates on Company offerings and recommendations for saving energy as new information becomes available. Current and archived news releases can be viewed at: https://www.dominionenergy.mediaroom.com.

Online Energy Calculators
State: Virginia and North Carolina
Home and business energy calculators are provided on the Company's website to estimate electrical usage for homes and business facilities. The calculators can help customers understand specific energy use by location and discover new means to reduce usage and save money. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at: https://www.dominionenergy.com/home-and-small-business/ways-to-save/energy-saving-calculators.

Community Outreach - Trade Shows, Exhibits, and Speaking Engagements
State: Virginia and North Carolina
The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation program information to both internal and external audiences. The Company also participates in various trade shows and exhibits at energy-related events to educate customers on the Company's DSM programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses. Additionally, Company representatives positively impact the communities the Company serves through presentations to elementary, middle, and high school students about its programs, wise energy use, and environmental stewardship.

For example, Project Plant It! is an educational community learning program available to students in the service areas where the Company conducts business. The program teaches students about the importance of trees and how to protect the environment through a variety of hands-on teaching tools such as a website with downloadable classroom lesson plans, instructional videos, and interactive games. To enhance the learning experience, Project Plant It! provides each enrolled student with a redbud tree seedling to plant at home or at school. From 2007 to 2018, more than 500,000 tree seedlings will have been distributed to children in states where the Company operates. According to the Virginia Department of Forestry, this equates to about 1,250 acres of new forest if all of the seedlings are planted and grow to maturity.

DSM Program Communications

The Company uses numerous methods to make customers aware of its DSM programs. These methods include direct mail, communications through contractor networks, e-mail, radio ads, social media, and outreach events.

3.2.5 APPROVED DSM PROGRAMS

On October 3, 2016, the Company filed for SCC approval (Case No. PUE-2016-00111) of one residential DSM program and one non-residential DSM program. The two proposed programs were the (i) Residential Home Energy Assessment and (ii) Non-Residential Prescriptive Program. In addition, the Company filed for extension of (i) the Residential Heat Pump Upgrade Program and (ii) the Non-Residential Distributed Generation Program. On June 1, 2017, the SCC issued its Final Order approving the Non-Residential Prescriptive Program and the continuation of the Non-Residential Distributed Generation Program for five years, and denied the Residential Home Energy Assessment and the continuation of the Residential Heat Pump Upgrade Program.

In North Carolina, in Docket No. E-22, Sub 543, the Company filed for approval of the Non-Residential Prescriptive Program. This is the same Program that was approved in Virginia in Case No. PUE-2016-00111. On October 16, 2017, the NCUC approved the new Program, which has been available to qualifying North Carolina customers since January 2018.

Appendix 3M provides program descriptions for the currently active DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing, and plans to achieve each program's penetration goals. Appendices 3N, 3O, 3P and 3Q provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved program.

3.2.6 PROPOSED DSM PROGRAM EXTENSION

On October 3, 2017, as part of Case No. PUR-2017-00129, the Company filed for a 5 year extension of the Phase IV Residential Income & Age Qualifying Home Improvement Program. The SCC is expected to issue its Final Order by early June 2018.

3.2.7 EVALUATION, MEASUREMENT & VERIFICATION

The Company has implemented evaluation, measurement, and verification ("EM&V") plans to quantify the level of energy and demand savings for approved DSM programs in Virginia and North Carolina. As required by the SCC and NCUC, the Company provides annual EM&V reports that include: (i) the actual EM&V data; (ii) the cumulative results for each DSM program in comparison to forecasted annual projections; and (iii) any recommendations or observations following the analysis of the EM&V data. These reports are filed annually with the SCC and NCUC and provide information through the prior calendar year. DNV GL (formerly DNV KEMA Energy & Sustainability), a third-party vendor, continues to be responsible for developing, executing, and reporting the EM&V results for the Company's currently-approved DSM programs.

In 2017, the SCC held a hearing in Case No. PUR-2017-00047 and issued additional rules and regulations regarding DSM planning and EM&V requirements. The Company will fully comply with all requirements in future DSM proceedings and include the results in future Plans.

3.3 TRANSMISSION RESOURCES

3.3.1 EXISTING TRANSMISSION RESOURCES

The Company has approximately 6,600 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV. These facilities are integrated into PJM.

3.3.2 EXISTING TRANSMISSION & DISTRIBUTION LINES

North Carolina Plan Addendum 2 contains the list of the Company's existing transmission and distribution lines from the most recently filed Federal Energy Regulatory Commission ("FERC") Form 1.

3.3.3 TRANSMISSION PROJECTS UNDER CONSTRUCTION

A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 3R.

CHAPTER 4 – PLANNING ASSUMPTIONS

4.1 PLANNING ASSUMPTIONS INTRODUCTION

In this 2018 Plan, the Company relies upon a number of assumptions including requirements from PJM. This Chapter discusses these assumptions and requirements related to capacity needs, reserves, renewable energy, commodity prices, DSM programs, transmission, and natural gas supply. The Company updates its IRP assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.1.1 VIRGINIA RGGI ASSUMPTIONS

For purposes of Plans B, C, and D, the Company assumed that it would be allocated 78% of the total CO_2 allowances for Virginia. This is based on the Company's historic average share of the statewide total CO_2 emissions. Currently, the DEQ has proposed to allocate an initial set of allowances (vintage 2020) to existing sources (i.e., units that are operational before January 1, 2020) in May 2019 based on average annual 2016 to 2018 generation output (MWh). Post-2020 allocations would be allocated in three-year blocks, beginning with allocations for 2021 to 2023 in May 2020, and updated every three years, based on the previous three years of generation output. New sources (i.e., operational after January 1, 2020) would not receive allowances until they have amassed three years of output data. There is no set aside proposed for new sources.

4.1.2 SOLAR INTEGRATION COST ASSUMPTIONS

A key resource included in this 2018 Plan is solar PV. As discussed in Chapter 5, current solar PV technology produces intermittent energy that is non-dispatchable and subject to sudden changes in generation output and to voltage inconsistencies. Therefore, integrating large volumes of solar PV into the Company's grid presents service reliability challenges that the Company continues to examine and study. In the Alternative Plans described in Chapter 6, a $155/kW fixed charge was phased into the cost of solar PV to function as an estimated charge for transmission and distribution integration costs. Further, a $1.78/MWh variable charge was added to the dispatch price of solar PV generation to address generation re-dispatch costs. A full description of the analysis conducted by the Company to estimate these costs is included in Section 5.1.3.1. It should be emphasized that, although more defined than the proxy costs included in the Company's previous Plans, the solar PV integration costs remain high level estimates. Costs such as advanced communications and control systems, intelligent grid devices, energy storage devices, increased operating reserve costs, natural gas nomination revision costs, and increased equipment operation and maintenance ("O&M") costs (due to increased cycling) are not included in these integration cost estimates. The Company continues to assess all costs associated with intermittent generation integration and intends to include those results in future Plans.

4.2 PJM CAPACITY PLANNING PROCESS & RESERVE REQUIREMENTS

The Company participates in the PJM capacity planning process for short- and long-term capacity planning. A discussion of this process and the Company's participation in it is provided in the following subsections.

4.2.1 SHORT-TERM CAPACITY PLANNING PROCESS – RPM

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines. PJM then conducts a capacity auction through its Short-Term Capacity Planning Process (i.e., the RPM auction) for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the delivery year that is three years in the future (e.g., the 2018 auction procures capacity for the delivery year 2021/2022).

As a generation provider, the Company bids its capacity resources, including owned and contracted generation and DSM programs, into the RPM auction. As an LSE, the Company is obligated to obtain enough capacity to cover its PJM-determined capacity requirements either from the RPM auction or through any bilateral trades. Figure 4.2.2.1 provides the Company's estimated 2019 to 2020 capacity positions and associated reserve margins based on PJM's 2018 Load Forecast and the RPM auctions that have already been conducted.

4.2.2 LONG-TERM CAPACITY PLANNING PROCESS – RESERVE REQUIREMENTS

The Company uses PJM's reserve margin guidelines in conjunction with its own load forecast, as discussed in Chapter 2, to determine its long-term capacity requirement. PJM conducts an annual reserve requirement study to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a loss of load expectation ("LOLE") equivalent to one day of outage in 10 years. PJM's 2017 Reserve Requirement Study for delivery year 2021/2022, recommended using an installed reserve margin ("IRM") of 15.9% to satisfy the NERC/Reliability First Corporation ("RFC") Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation.

PJM develops reserve margin estimates for planning years (referred to as "delivery years" for RPM) rather than calendar years. [23] Specifically, PJM's planning year runs from June 1st to May 31st. Because the Company and PJM are both historically summer peaking entities, and because the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer time period. For example, the Company uses PJM's 2019/2020 delivery year assumptions for the 2019 calendar year in this 2018 Plan because it represents the expected peak load during the summer of 2019.

Two assumptions were made by the Company when applying the PJM reserve margin to the Company's modeling efforts. First, since PJM uses a shorter planning period than the Company, the Company used the most recent PJM Reserve Requirements Study and assumed the reserve margin value for delivery year 2021 and beyond would continue throughout the Study Period.

The second assumption pertains to the coincident factor between the DOM Zone coincidental and non-coincidental peak load. The Company is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load. Since the Company's peak load (non-coincidental) has not historically occurred during the same hour as PJM's peak load (coincidental), a smaller reserve margin is needed to meet reliability targets and is based on a coincidence factor. To determine the coincidence factor used in this 2018 Plan, the Company used a four-year (2018 to 2021) average of the coincidence factor between the DOM Zone coincidental and non-coincidental peak load. The coincidence factor for the Company's load is approximately 96.47%, as calculated using PJM's 2018 Load Forecast. In 2021, applying the PJM IRM requirement of 15.9% with the Company's coincidence factor of 96.47% resulted in an effective reserve margin of 11.7%, as shown in Figure 4.2.2.1. This effective reserve margin was then used for each year for the remainder of the Study Period.

As a member of PJM, the Company participates in the annual RPM capacity market. PJM's RPM construct has historically resulted in a clearing reserve margin in excess of the planned reserve margin requirement. The average PJM RPM clearing reserve margin is 20.3% over the past five years.[24] Using the same analytical approach described above, this equates to an approximate 15.9% effective reserve requirement. With the RPM clearing capacity in excess of its target level,

[23] PJM's current and historical reserve margins are available at http://www.pjm.com/~/media/committees-groups/subcommittees/raas/20160927/20160927-2017-pjm-reserve-requirement-study.ashx.

[24] See http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.

the Company has purchased reserves in excess of the 11.7% planning reserve margin, as reflected in Figure 4.2.2.1. Given this history, the figures in Appendix 1A display a second capacity requirement that includes an additional 5% reserve requirement target (16.7% reserve margin) that is commensurate with the upper bound where the RPM market has historically cleared. Nevertheless, the Company's planning reserve margin minimum target remains at the 11.7% average clearing level. The upper bound reserve margin reflects the reserve margin that the Company may be required to meet in the future.

Figure 4.2.2.1 - Peak Load Forecast & Reserve Requirements

Year	PJM Installed Reserve Margin Requirements	DEV Effective Reserve Margin Requirements	Total System Summer Peak	Adjusted System Summer Peak	Reserve Requirement	Total Resource Requirement
	%	%	MW	MW	MW	MW
2019	15.90%	11.87%	17,868	17,674	2,098	19,773
2020	15.90%	11.84%	17,968	17,766	2,103	19,869
2021	15.80%	11.75%	18,229	18,026	2,118	20,144
2022	15.80%	11.74%	18,486	18,284	2,147	20,431
2023	15.80%	11.74%	18,762	18,559	2,179	20,738
2024	15.80%	11.74%	19,227	19,025	2,234	21,259
2025	15.80%	11.74%	19,551	19,351	2,272	21,624
2026	15.80%	11.74%	19,880	19,682	2,311	21,993
2027	15.80%	11.74%	20,097	19,899	2,337	22,236
2028	15.80%	11.74%	20,292	20,093	2,359	22,453
2029	15.80%	11.74%	20,587	20,389	2,394	22,784
2030	15.80%	11.74%	20,931	20,733	2,435	23,168
2031	15.80%	11.74%	21,167	20,967	2,462	23,429
2032	15.80%	11.74%	21,334	21,133	2,482	23,615
2033	15.80%	11.74%	21,499	21,297	2,501	23,798

Note: Values include energy efficiency.

In Figure 4.2.2.1, the total resource requirement provides the total amount of peak capacity including the reserve margin used in this 2018 Plan. This represents the Company's total resource need that must be met through existing resources, construction of new resources, DSM programs, and market capacity purchases. Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annually updated load and reserve requirements. Appendix 2I provides a summary of summer and winter peak load and energy forecast, while Appendix 2J provides a summary of projected PJM reserve margins for summer peak demand.

4.3 RENEWABLE ENERGY

4.3.1 VIRGINIA RPS

On May 18, 2010, the SCC issued its Final Order granting the Company's July 28, 2009 application to participate in Virginia's voluntary Renewable Energy Portfolio Standards ("RPS") program finding that "the Company has demonstrated that it has a reasonable expectation of achieving 12% of its base year electric energy sales from renewable energy sources during calendar year 2022, and 15% of its base year electric energy sales from renewable energy sources during calendar year 2025" (Case No. PUE-2009-00082, May 18, 2010 Final Order at 7). The RPS guidelines state that a certain percent of the Company's energy is to be obtained from renewable resources. The Company can meet Virginia's RPS program guidelines through the generation of renewable energy, purchase of renewable energy, purchase of RECs, or a combination of these three options. Figure 4.3.1.1 displays Virginia's RPS goals.

Figure 4.3.1.1 - Virginia RPS Goals

Year	Percent of RPS	Annual GWh[1]
2017-2021	Average of 7% of Base Year Sales	3,032
2022	12% of Base Year Sales	5,198
2023-2024	Average of 12% of Base Year Sales	5,198
2025	15% of Base Year Sales	6,497
2026-2017	15% of Base Year Sales	6,497

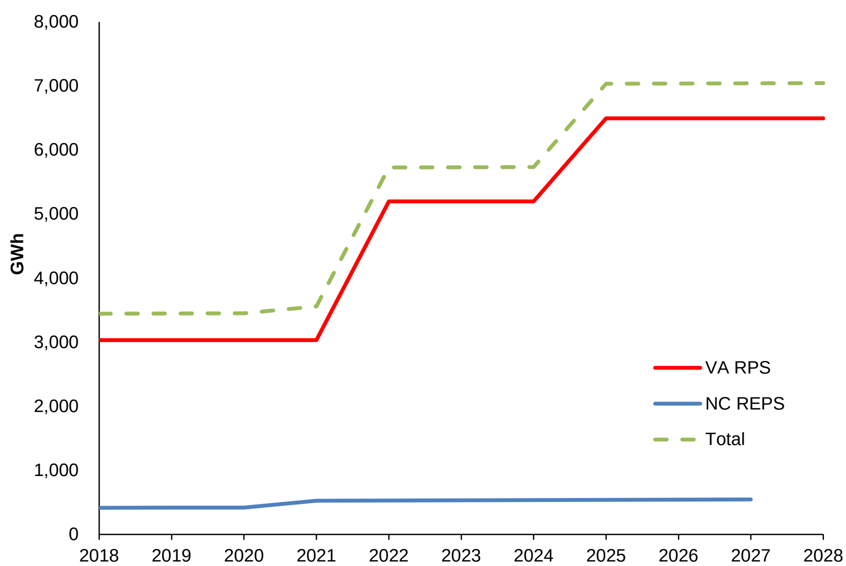
Note: 1) Base year sales are equal to 2007 Virginia jurisdictional retail sales, minus 2004 to 2006 average nuclear generation. Actual goals are based on MWh.

The Company has included renewable resources as an option in PLEXOS, taking into consideration the economics and RPS requirements. If there are adequate supplies of waste wood, VCHEC is expected to provide up to 61 MW of renewable generation by 2021.

The Company achieved its 2016 Virginia RPS Goal. The Company reiterates its intent to meet Virginia's RPS guidelines at a reasonable cost and in a prudent manner by: (i) applying renewable energy from existing generating facilities including NUGs; (ii) purchasing cost-effective RECs (including optimizing RECs produced by Company-owned generation (i.e., when higher priced RECs are sold into the market and less expensive RECs are purchased and applied to the Company's RPS goals); and (iii) constructing new renewable resources when and where feasible.

The renewable energy requirements for Virginia and North Carolina and their totals are shown in Figure 4.3.1.2.

Figure 4.3.1.2 - Renewable Energy Requirements



4.3.2 NORTH CAROLINA REPS

NCGS § 62-133.8 requires the Company to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") requirements. The REPS requirements can be met by generating renewable energy, energy efficiency measures (capped at 25% of the REPS requirements through 2020 and 40% thereafter), purchasing renewable energy, purchasing RECs, or a combination of options as permitted by NCGS § 62-133.8 (b) (2). The Company plans to meet a portion of the general REPS requirement using the approved energy efficiency programs discussed in Chapters 3 and 5 of this 2018 Plan.

Figure 4.3.2.1 displays North Carolina's overall REPS requirements. Additionally, as part of the total REPS requirements, North Carolina requires certain renewable set-aside provisions for solar energy, swine waste, and poultry waste resources, as shown in Figures 4.3.2.2, 4.3.2.3, and 4.3.2.4.

Figure 4.3.2.1 - North Carolina Total REPS Requirement

Year	Percent of REPS	Annual GWh[1]
2018	10% of 2017 DENC Retail Sales	415
2019	10% of 2018 DENC Retail Sales	417
2020	10% of 2019 DENC Retail Sales	419
2021	12.5% of 2020 DENC Retail Sales	526
2022	12.5% of 2021 DENC Retail Sales	529
2023	12.5% of 2022 DENC Retail Sales	533
2024	12.5% of 2023 DENC Retail Sales	536
2025	12.5% of 2024 DENC Retail Sales	539
2026	12.5% of 2025 DENC Retail Sales	542
2027	12.5% of 2026 DENC Retail Sales	546
2028	12.5% of 2027 DENC Retail Sales	549

Note: 1) Annual GWh is an estimate only based on the latest forecast sales. The Company intends to comply with the North Carolina REPS requirements, including the set-asides for energy derived from solar, poultry waste, and swine waste through the purchase of RECs and/or purchased energy, as applicable. The set-aside requirements represent approximately 0.03% of system load by 2024 and will not materially alter this 2018 Plan.

Figure 4.3.2.2 - North Carolina Solar Requirement

Year	Requirement Target (%)	Annual GWh[1]
2018	0.20% of 2017 DENC Retail Sales	8.30
2019	0.20% of 2018 DENC Retail Sales	8.33
2020	0.20% of 2019 DENC Retail Sales	8.37
2021	0.20% of 2020 DENC Retail Sales	8.42
2022	0.20% of 2021 DENC Retail Sales	8.47
2023	0.20% of 2022 DENC Retail Sales	8.52
2024	0.20% of 2023 DENC Retail Sales	8.57
2025	0.20% of 2024 DENC Retail Sales	8.63
2026	0.20% of 2025 DENC Retail Sales	8.68
2027	0.20% of 2026 DENC Retail Sales	8.73
2028	0.20% of 2027 DENC Retail Sales	8.78

Notes: 1) Annual GWh is an estimate based on latest forecast sales.

Figure 4.3.2.3 - North Carolina Swine Waste Requirement

Year	Target[1]	DENC Market Share (Est.)	Annual GWh
2018	0.07% of 2017 NC Retail Sales	3.02%	2.87
2019	0.07% of 2018 NC Retail Sales	3.00%	2.89
2020	0.14% of 2019 NC Retail Sales	2.99%	5.81
2021	0.14% of 2020 NC Retail Sales	2.98%	5.85
2022	0.14% of 2021 NC Retail Sales	2.96%	5.88
2023	0.20% of 2022 NC Retail Sales	2.95%	8.46
2024	0.20% of 2023 NC Retail Sales	2.94%	8.51
2025	0.20% of 2024 NC Retail Sales	2.93%	8.56
2026	0.20% of 2025 NC Retail Sales	2.92%	8.64
2027	0.20% of 2026 NC Retail Sales	2.91%	8.69
2028	0.20% of 2027 NC Retail Sales	2.89%	8.75

Note: 1) Annual GWh is an estimate based on the latest forecast sales.

Figure 4.3.2.4 - North Carolina Poultry Waste Requirement

Year	Target (GWh)	DENC Market Share (Est.)	Annual GWh[1]
2018	700	3.02%	21.13
2019	900	3.00%	27.00
2020	900	2.99%	26.89
2021	900	2.98%	26.78
2022	900	2.96%	26.68
2023	900	2.95%	26.57
2024	900	2.94%	26.47
2025	900	2.93%	26.36
2026	900	2.92%	26.26
2027	900	2.91%	26.15
2028	900	2.89%	26.05

Note: 1) For purposes of this filing, the Poultry Waste Resource requirement is calculated as an aggregate target for NC electric suppliers distributed based on market share. On April 18, 2016, the NCUC established a procedure to allocate the poultry waste set-aside by averaging three years of historical retail sales and using the resulting load share ratio for the following three years.

The Company achieved compliance with its 2016 North Carolina REPS general obligation by using approved North Carolina energy efficiency savings and banked RECs, and by purchasing additional qualified RECs. In addition, the Company purchased sufficient RECs to comply with the solar and poultry waste set-aside requirements. However, on October 16, 2017, in response to the Joint Motion to Modify and Delay, the NCUC delayed the Company's 2017 swine waste set-aside requirement one year and delayed the poultry waste set-aside requirement increase for one year. More information regarding the Company's REPS compliance planning is available in its North Carolina REPS Compliance Plan filed in North Carolina with this 2018 Plan as North Carolina Plan Addendum 1.

4.4 COMMODITY PRICE ASSUMPTIONS

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analysis in this 2018 Plan using energy and commodity price forecasts provided by ICF in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, and power prices rely on forward market prices as of December 29, 2017, for the first 18 months of the Study Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity prices are provided by ICF for all years forecasted within this 2018 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM Base Residual Auction through the 2020/2021 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2021/2022 delivery year.

The key assumptions on market structure and the use of an integrated, internally-consistent fundamentals-based modeling methodology remain consistent with those utilized in the prior years' commodity forecasts. In the 2018 Plan, the Company utilizes three commodity forecasts to evaluate the Plan(s). The three forecasts used in the Plan are the Federal CO_2 commodity forecast, the No CO_2 Tax commodity forecast, and the Virginia RGGI commodity forecast.

4.4.1 FEDERAL CO_2 COMMODITY FORECAST

The Federal CO_2 commodity forecast was developed for the Company to address a future market environment where carbon regulations affect electric generation plants. The Company utilized this commodity forecast in the analysis of Plan E. Utilizing the Federal CO_2 commodity forecast allows the Company to evaluate Plan E using a commodity price forecast that reflects ICF's independent view of future market conditions including potential regulations on carbon emissions from electric generation activities. ICF's independent internal views of key market drivers include: (i) market structure and policy elements that shape allowance; (ii) fuel and power markets ranging from expected capacity and pollution control installations; (iii) environmental regulations; and (iv) fuel supply-side issues. The development process assesses the impact of environmental regulations on the power and fuel markets and incorporates ICF's latest views on the outcome of new regulatory initiatives. The Federal CO_2 commodity forecast provides prices for fuel, energy, capacity, emission allowances, and RECs.

In the Federal CO_2 commodity forecast, the assumptions for CO_2 regulation represent a probability weighted outcome of legislative and regulatory initiatives, including the possibility of no regulatory program addressing CO_2 emissions. A charge on CO_2 emissions from the power sector is assumed to begin in 2026.

The Federal CO_2 commodity forecast considers three potential outcomes. The first possible outcome considers a $0/ton CO_2 price; the second possible outcome considers a tradable mass-based program (i.e., limit on tonnage of CO_2 emissions) on existing and new sources; and a third possible outcome considers a more stringent legislative approach.

The $0/ton price under the first possible outcome can be thought of as either no-program or a "behind-the-fence" requirement without a market-based CO_2 price.

The second possible outcome is considered a "mid" case approach to carbon regulation that reflects a delay in the implementation of the CPP. While it is likely that a replacement for the CPP promulgated under a future regulation would include different requirements, ICF relies on the requirements of this representative "mid" case for future CO_2 regulations of the power sector. This representation assumes that states adopt mass-based standards within a regional trading structure. It assumes that California and RGGI states address leakage by including new sources, while remaining regions only include existing sources and address leakage through alternative measures.

This representation also assumes RGGI and the California-specific programs continue as individual programs.

The third possible outcome—a "high" case approach—assumes a legislative approach to a national mass cap-and-trade program that begins in 2028 and targets an approximately 80% reduction from 2005 sector emissions by 2050. This target is similar to levels being discussed by several states, and it is consistent with what was proposed under the Waxman-Markey Bill. The "high" case includes existing and new sources under a national cap and trade program. This representation assumes that all states participate in the program except for California, which maintains its state specific program.

In 2030, the Federal CO_2 commodity forecast assumed a 40% probability for the $0/ton outcome, a 50% probability of a "mid" case type program and a 10% probability for the "high" case legislative mass cap based program. By 2040, the probability of a CO_2 price by means of the mid and high case programs increases to 85%. The resulting CO_2 price forecast rises from a little over $3.50/ton (nominal $) in 2030 to over $20/ton in 2040 in the Federal CO_2 commodity forecast.

Comparisons of the Federal CO_2 commodity forecast used in this 2018 Plan and the CPP commodity forecast used in the 2017 Plan are provided below. Figures 4.4.1.1 through 4.4.1.5 display the fuel price forecasts, while Figure 4.4.1.6 displays the forecasted price for SO_2 and NO_x on a dollar per ton basis. Figure 4.4.1.7 displays CO_2 emissions allowances ($/ton). Figures 4.4.1.8 and 4.4.1.9 present the forecasted market clearing price for peak and off peak power prices for the DOM Zone. The PJM RTO capacity price forecast is presented in Figure 4.4.1.10. Appendix 4B provides delivered fuel prices and primary fuel expense from the PLEXOS model output using the Federal CO_2 commodity forecast.

Figure 4.4.1.1 – Fuel Price Forecasts - Natural Gas Henry Hub

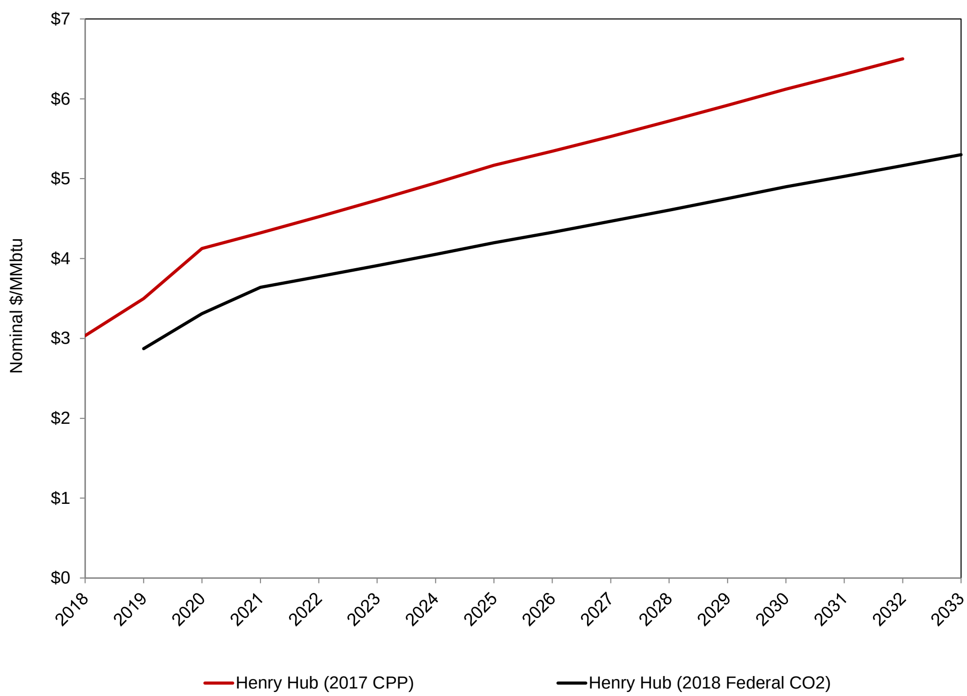


Figure 4.4.1.2 – Fuel Price Forecasts - Natural Gas DOM Zone

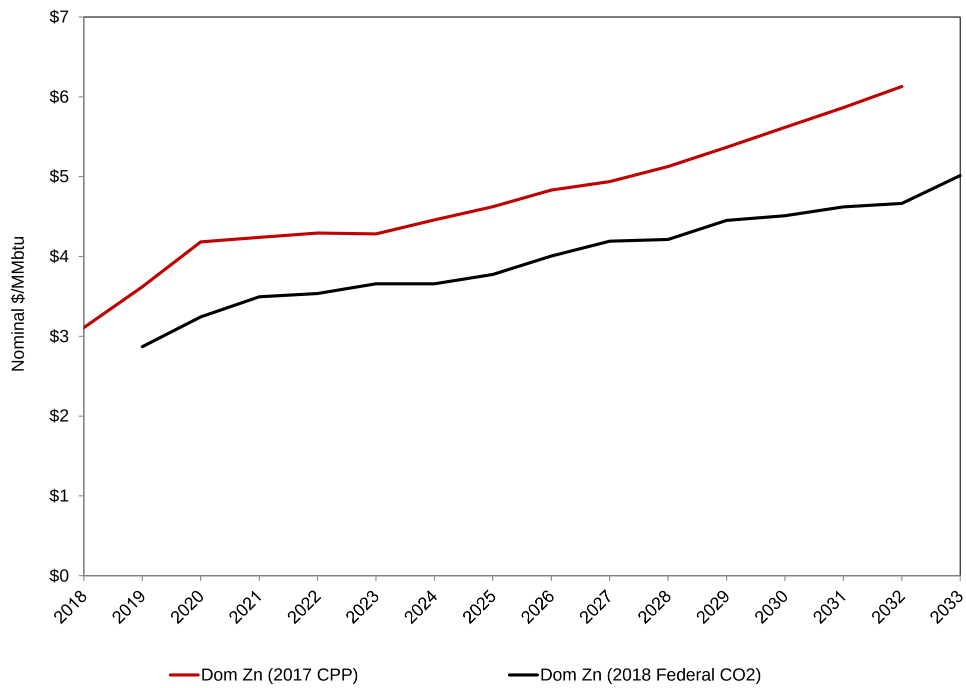


Figure 4.4.1.3 – Fuel Price Forecasts - Coal

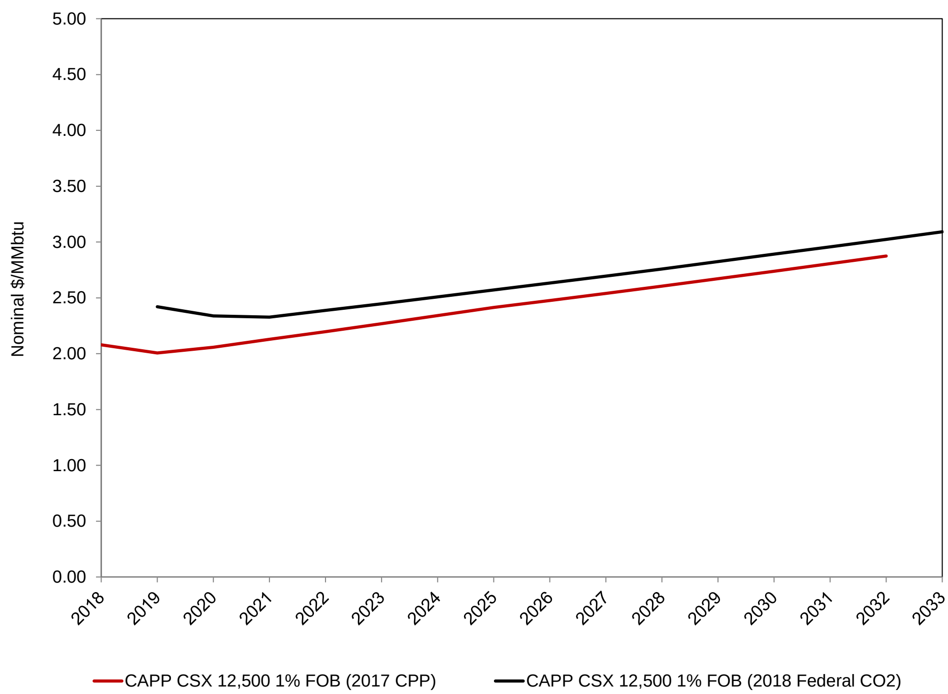


Figure 4.4.1.4 – Fuel Price Forecasts - #2 Oil

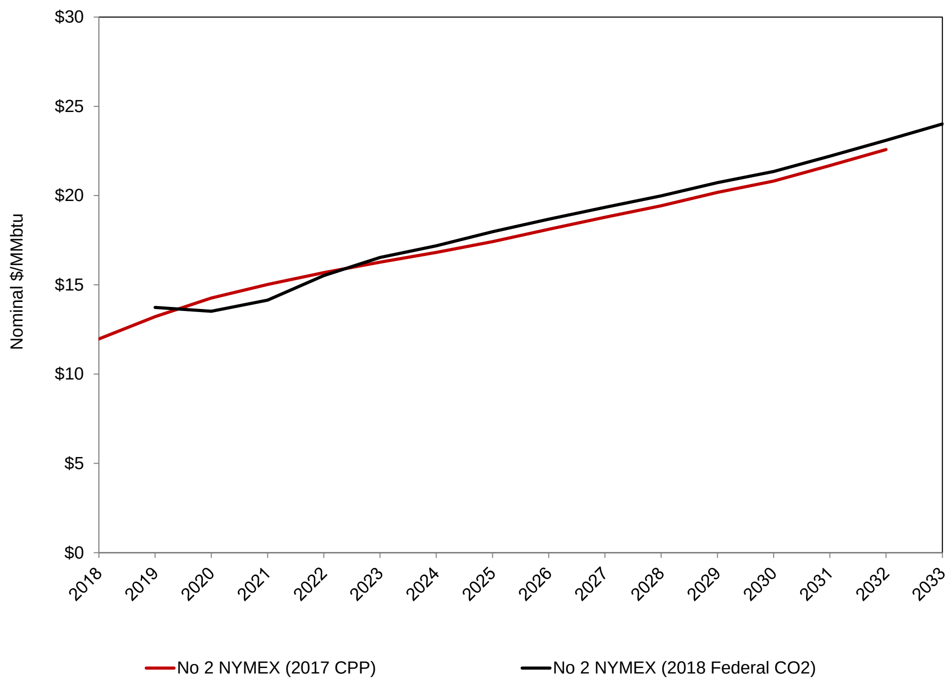


Figure 4.4.1.5 – Fuel Price Forecasts – #6 Oil

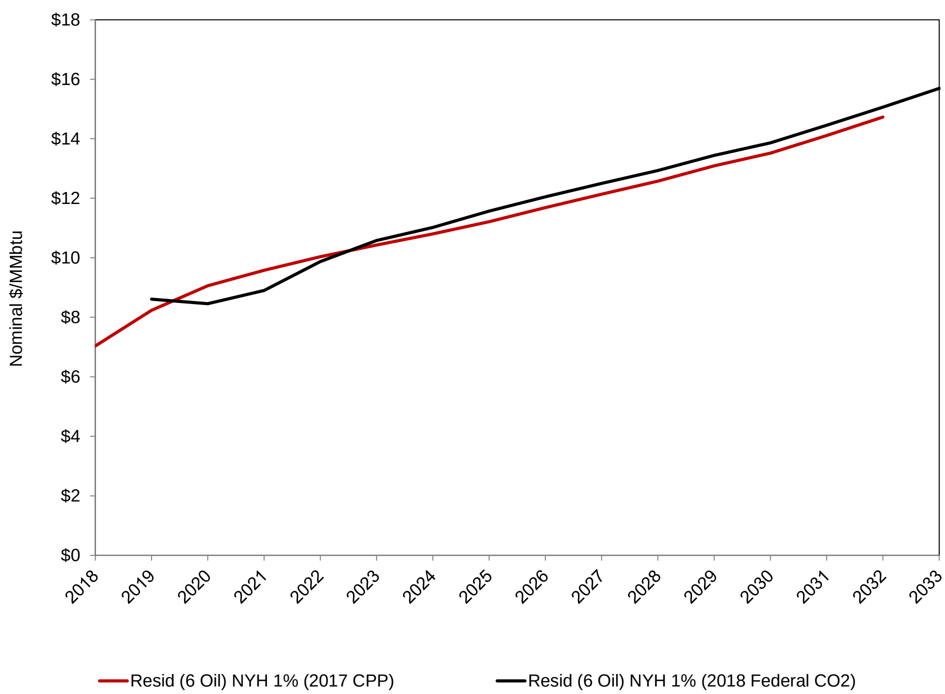


Figure 4.4.1.6 – Allowance Price Forecasts – SO_2 & NO_X

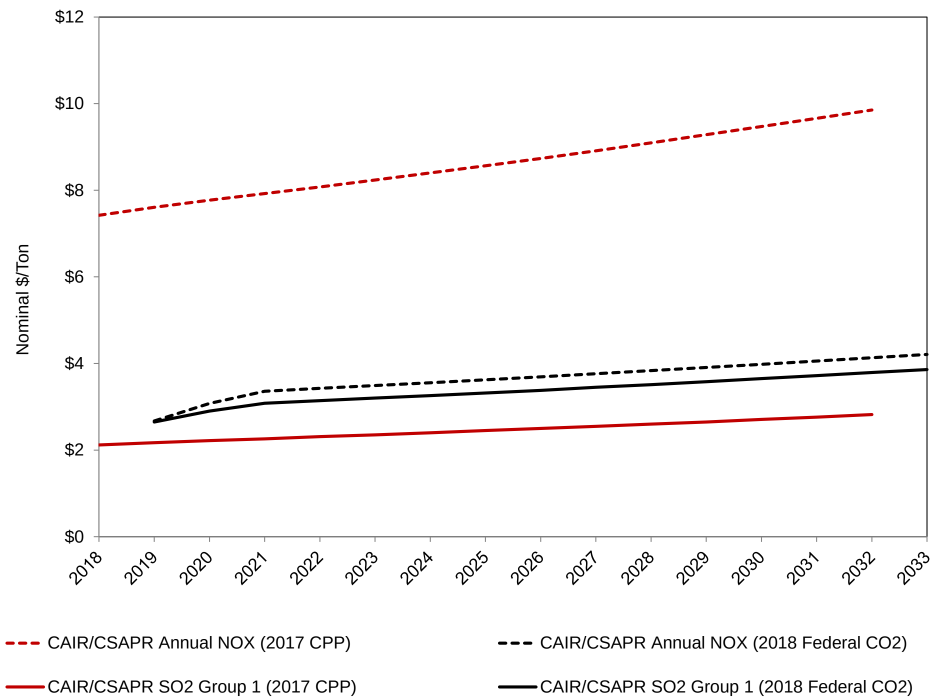
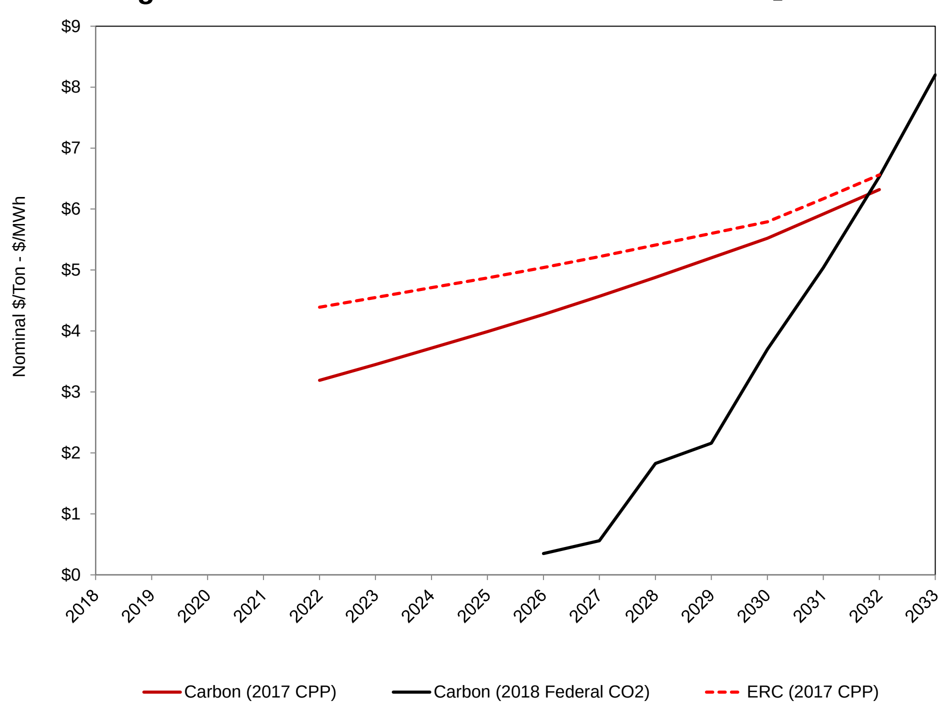


Figure 4.4.1.7 – Allowance Price Forecasts - CO_2



Note: The Federal CO_2 commodity forecast used in the 2018 Plan includes a CO_2 allowance price on a per ton basis. In the 2017 Plan, the commodity forecast modeled a CPP-type carbon regulation program. In such a program, there would be both emission rate credit forecast ($/MWh), which applies to states adopting an intensity-based compliance program, and a CO_2 allowance price forecast ($/ton), which applies to states adopting a mass-based compliance program. The Federal CO_2 commodity forecast did not include an emission rate credit forecast because it assumes that states will adopt mass-based compliance programs.

Figure 4.4.1.8 – Power Price Forecasts – On Peak

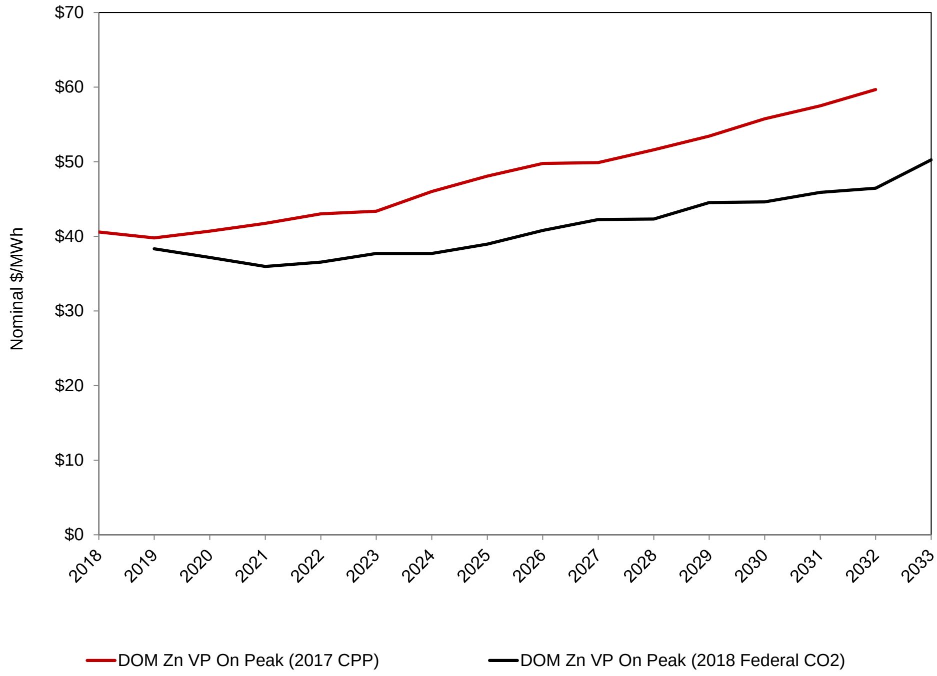


Figure 4.4.1.9 – Power Price Forecasts – Off Peak

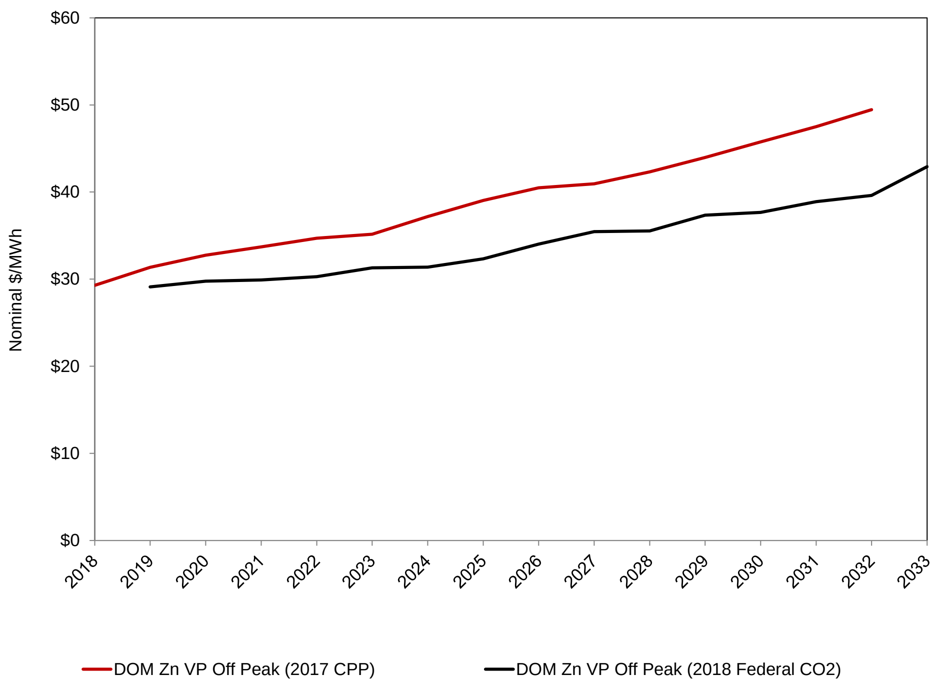
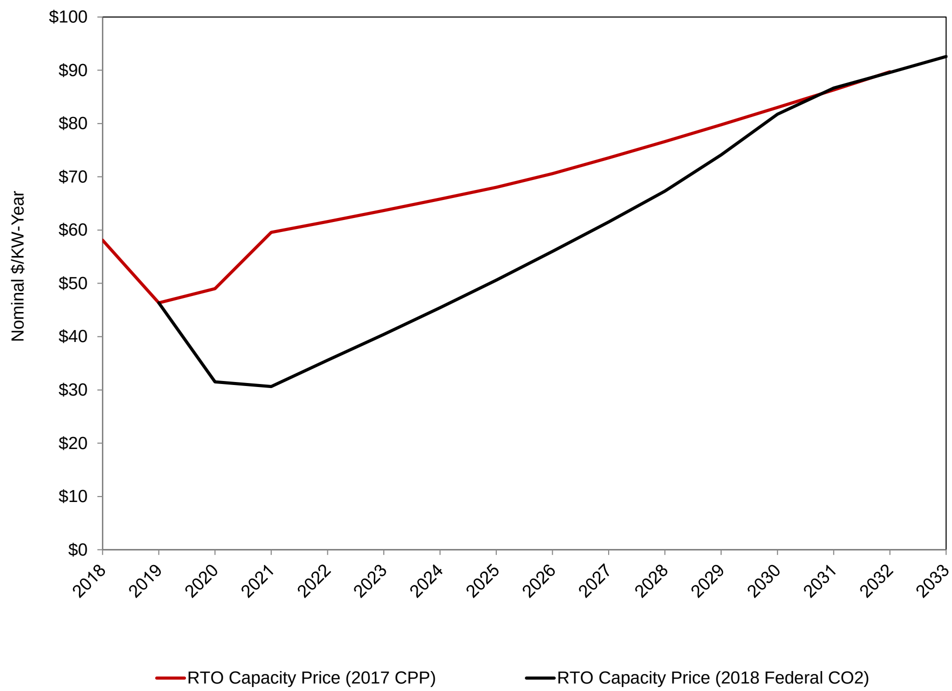


Figure 4.4.1.10 – PJM RTO Capacity Price Forecasts



The forecast of power and gas prices are lower this year than forecasted in the 2017 Plan. Lower power prices result from a combination of factors, most notably lower gas prices and lower load growth forecasts. Lower gas prices reflect the decrease in cost and increase in volume of the shale gas resources and, over the longer term, the revised assumption that nuclear units are likely to renew their licenses to 80 years. Capacity prices are also lower, reflecting the results of the last auction and the reduction of the assumed risk premium penalties. Figure 4.4.1.11 presents a comparison of average fuel, electric, and REC prices used in the 2017 Plan relative to those used in this 2018 Plan.

Figure 4.4.1.11 – 2017 Plan to 2018 Plan Fuel & Power Price Comparison

	Planning Period Comparison Average Value (Nominal $)	
Fuel Price	2017 Plan CPP Commodity Forecast [3]	2018 Plan Federal CO_2 Commodity Forecast [3]
Henry Hub Natural Gas[1] ($/MMbtu)	5.05	4.29
DOM Zone Delivered Natural Gas[1] ($/MMbtu)	4.71	3.99
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.41	2.66
No. 2 Oil ($/MMbtu)	17.48	18.52
1% No. 6 Oil ($/MMbtu)	11.22	11.93
PJM-DOM On-Peak ($/MWh)	48.05	41.29
PJM-DOM Off-Peak ($/MWh)	38.91	34.36
PJM Tier 1 REC Prices ($/MWh)	15.32	7.04
RTO Capacity Prices[2] ($/kW-yr)	68.79	59.33

Note: 1) DOM Zone natural gas price used as a representative gas price for Virginia. Henry Hub prices are shown to provide market reference.
2) Capacity price represents actual clearing price from PJM Reliability Pricing Model. Base Residual Auction results through power year 2019/2020 for the 2017 Plan and 2020/2021 for the 2018 Plan.
3) 2017 Planning Period 2018 – 2032, 2018 Planning Period 2019 – 2033.

4.4.2 ADDITIONAL COMMODITY PRICES

The alternative commodity price forecasts represent reasonable outcomes for future commodity prices based on alternate views of key fundamental drivers of commodity prices. However, as with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this Plan. History has shown that unforeseen events, and events not contemplated 5 or 10 years before their occurrence, can result in significant changes in market fundamentals. A recent example is the shale gas revolution that transformed the pricing structure of natural gas. Another recent example is the retirement of numerous, coal-fueled generation units, in response to low gas prices, an aging coal fleet, and environmental compliance cost.

The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in this 2018 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes. In this 2018 Plan, the Company has included a comprehensive risk analysis that provides a more robust assessment of possible price forecast outcomes. A description of this analysis is included in Chapter 6.

The Company utilizes the No CO_2 Tax commodity forecast to evaluate Plan A, which anticipates a future without any new regulations or restrictions on CO_2 emissions. In this forecast, the cost associated with carbon emissions is removed from the commodity forecast. DOM Zone peak energy prices are slightly lower than the Federal CO_2 commodity forecast across the Planning Period as there is no CO_2 cost to pass through to power prices. To be clear, the Company expects that some form of GHG regulations or legislation will occur and plans accordingly. The No CO_2 Tax forecast is only utilized in analysis of Plan A, which is used to measure the cost of GHG program compliance.

The Company utilizes the Virginia RGGI commodity forecast to evaluate Alternative Plans B, C, and D. The Virginia RGGI forecast assumes that Virginia joins RGGI (either directly or indirectly through the Virginia RGGI Program). The primary reason for developing this forecast was to allow the Company to evaluate the Alternative Plans compliant with Virginia RGGI or RGGI using a commodity price forecast that reflects Virginia linking to RGGI. The key assumptions on market structure and the use of an integrated, internally-consistent fundamental based modeling methodology remain consistent with those utilized in the Federal CO_2 commodity forecast except that the carbon program modeled is RGGI, which begins in 2020, and that there is no national program as used in the Federal CO_2 commodity forecast.

Appendix 4A provides the annual prices (nominal $) for the Federal CO_2 commodity forecast, the No CO_2 Tax commodity forecast, and the Virginia RGGI commodity forecast. Figure 4.4.2.1 provides a comparison of the Federal CO_2 commodity forecast, the No CO_2 Tax commodity forecast, and the Virginia RGGI commodity forecast.

Figure 4.4.2.1 – 2018 Plan Fuel & Power Price Comparison

Fuel Price	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
Henry Hub Natural Gas ($/MMbtu)	4.29	4.29	4.29
DOM Zone Delivered Natural Gas ($/MMbtu)	3.99	3.88	3.99
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.66	2.67	2.67
No. 2 Oil ($/MMbtu)	18.52	18.52	18.52
1% No. 6 Oil ($/MMbtu)	11.93	11.93	11.93
Electric and REC Prices			
PJM-DOM On-Peak ($/MWh)	41.29	41.12	40.63
PJM-DOM Off-Peak ($/MWh)	34.36	34.11	33.80
PJM Tier 1 REC Prices ($/MWh)	7.04	9.06	9.19
RTO Capacity Prices ($/kW-yr)	59.33	60.37	60.76

4.5 DEVELOPMENT OF DSM PROGRAM ASSUMPTIONS

The Company develops assumptions for new DSM programs by engaging vendors through a competitive bid process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. The Company generally prefers, to the extent practical, that the program design vendor is ultimately the same vendor that implements the program in order to maintain as much continuity as possible from design to implementation.

The DSM program design process includes evaluating programs as either single measure, like the former Residential Heat Pump Upgrade Program, or multi-measure, like the Small Business Improvement Program. For all measures in a program, the design vendor develops a baseline for a standard customer end-use technology. The baseline establishes the current energy usage for a particular appliance or customer end-use. Next, assumptions for a more efficient replacement measure or end-use are developed. The difference between the more efficient energy end-use and the standard end-use provides the incremental benefit that the Company and customer will achieve if the more efficient energy end-use is implemented.

The program design vendor's development of assumptions for a DSM program include determining cost estimates for the incremental customer investment in the more efficient technology, the incentive that the Company should pay the customer to encourage investment in the efficient technology, and the program cost the Company will likely incur to administer the program. In addition to the cost assumptions for the program, the program design vendor develops incremental demand and energy reductions associated with the program. This data is represented in the form of a load shape for energy efficiency programs that identifies the energy reductions by hour for each hour of the year (8,760 hour load shape).

The Company then uses the program assumptions developed by the program design vendor to perform cost/benefit tests for the programs. The Company looks at the results of all of the cost/benefit test scores, as well as NPV results, to evaluate whether to file for regulatory approval of a potential program or program extension.

4.6 TRANSMISSION PLANNING

The Company's transmission planning process, system adequacy, transfer capabilities, and transmission interconnection process are described in the following subsections. As used in this 2018 Plan, electric transmission facilities can be generally defined as those operating at 69 kV and above that provide for the interchange of power within and outside of the Company's system.

4.6.1 REGIONAL TRANSMISSION PLANNING & SYSTEM ADEQUACY

The Company's transmission system is designed and operated to ensure adequate and reliable service to customers while meeting all regulatory requirements and standards. Specifically, the Company's transmission system is developed to comply with the NERC Reliability Standards, as well as the Southeastern Reliability Corporation supplements to the NERC Standards.

The Company participates in numerous regional, inter-regional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is a member of PJM, an RTO responsible for the movement of wholesale electricity. PJM is registered with NERC as the Company's planning coordinator and transmission planner. Accordingly, the Company participates in the PJM regional transmission expansion plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a 5-year and a 15-year outlook.

The Company evaluates its ability to support expected customer growth through its internal transmission planning process. The results of this evaluation will indicate if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate. If the need is confirmed, then the Company seeks approval for the transmission improvements from the appropriate regulatory body.

Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. The Company coordinates with neighboring utilities to maintain adequate levels of transfer capability to facilitate economic and emergency power flows.

4.6.2 STATION SECURITY

As part of the Company's overall strategy to improve its transmission system resiliency and security, the Company continues to install additional physical security measures at substations and switching stations in Virginia and North Carolina. The Company announced these plans following the widely-reported April 2013 Metcalfe Substation incident in California.

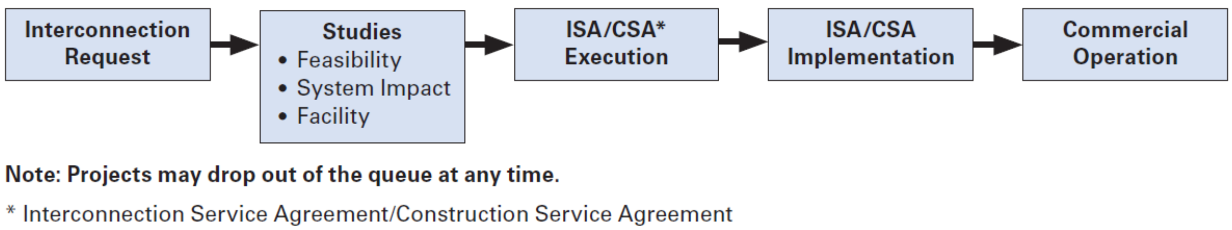
As one of the region's largest electricity suppliers, the Company formulated a plan to increase the security and resilience of its transmission substations and other critical infrastructure against man-made physical or cyber threats and natural disasters, and to procure mobile response equipment and stockpile crucial equipment for major damage recovery. These new security facilities will be installed in accordance with recently-approved NERC mandatory compliance standards. In addition, the Company has completed construction of its new System Operations Center, which was commissioned and became operational in August 2017.

4.6.3 TRANSMISSION INTERCONNECTIONS

For any new generation proposed within the Company's transmission system, either by the Company or by other parties, the generation owner files an interconnection request with PJM. PJM, in conjunction with the Company, conducts feasibility studies, system impact studies, and facilities studies to determine the facilities required to interconnect the generation to the transmission system (Figure 4.6.3.1). These studies ensure deliverability of the generation into the PJM market. The scope of these studies is provided in the applicable sections of PJM Manual 14A[25] and the Company's Facility Connection Requirements.[26]

The results of these studies provide the requesting interconnection customer with an assessment of the feasibility and costs (both interconnection facilities and network upgrades) to interconnect the proposed facilities to the PJM system, which includes the Company's transmission system.

Figure 4.6.3.1 - PJM Interconnection Request Process



Source: PJM

The Company's planning objectives include analyzing planning options for transmission, as part of the IRP process, and providing results from this process that become inputs to the PJM planning process. In order to accomplish this goal, the Company must comply and coordinate with a variety of regulatory groups, including NERC, PJM, FERC, the SCC, and the NCUC, that address reliability, grid expansion, and costs . In evaluating and developing this process, balance among regulations, reliability, and costs are critical to providing service to the Company's customers in all aspects, which includes generation and transmission services.

The Company also evaluates and analyzes transmission options for siting potential generation resources to offer flexibility and additional grid benefits. The Company conducts power flow studies and financial analysis to determine interconnection requirements for new supply-side resources.

The Company uses Promod IV®, which performs security-constrained unit commitment and dispatch, to consider the proposed and planned supply-side resources and transmission facilities. Promod IV® incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations, and is the industry-leading fundamental electric market simulation software.

The Promod IV® model enables the Company to integrate the transmission and generation system planning to: (i) analyze the zonal and nodal level locational marginal pricing ("LMP") impact of new resources and transmission facilities; (ii) calculate the value of new facilities due to the alleviation of system constraints; and (iii) perform transmission congestion analysis. The model is utilized to determine the most beneficial location for new supply-side resources in order to optimize the future need for both generation and transmission facilities, while providing reliable service to all customers.

[25] The PJM Manual 14A is posted at http://www.pjm.com/~/media/documents/manuals/m14a.ashx.
[26] The Company's Facility Connection Requirements are posted at https://www.dominionenergy.com/library/domcom/media/large-business/selling-power-to-dominion-energy/parallel-generation-and-interconnection/facility-connection-requirements.pdf.

The Promod IV® model evaluates the impact of resources under development that are selected by the PLEXOS model.

Historically, the Promod IV® and Power System Simulator for Engineering were utilized to evaluate the impact of future generation retirements on the reliability of the DOM Zone transmission grid. These evaluations are ongoing and not yet complete for the units identified as candidates for retirement and included in this 2018 Plan. At this stage, the Company has no definitive plans regarding any generating unit retirement.

4.7 GAS SUPPLY, ADEQUACY, & RELIABILITY

In maintaining its diverse generating portfolio, the Company manages a balanced mix of fuels that includes fossil, nuclear, and renewable resources. Specifically, the Company's fleet includes units powered by natural gas, coal, petroleum, uranium, biomass (waste wood), water, and solar. This balanced and diversified fuel management approach supports the Company's efforts in meeting its customers' growing demand by responsibly and cost-effectively managing risk. By avoiding overreliance on any single fuel source, the Company protects its customers from rate volatility and other harms associated with shifting regulatory requirements, commodity price volatility, and reliability concerns.

Electric Power and Natural Gas Interdependency

With a production shift from conventional to an expanded array of unconventional gas sources (such as shale) and relatively low commodity price forecasts, natural gas-fired generation continues to be a competitive choice for new capacity.

However, the electric grid's exposure to interruptions in natural gas fuel supply and delivery has increased with the generating capacity's growing dependence on a single fuel. Natural gas is largely delivered on a just-in-time basis, and vulnerabilities in gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective. Mitigating strategies such as storage, firm fuel contracts, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, and overall fuel diversity all help to alleviate this risk.

There are two types of pipeline delivery service contracts: firm and interruptible. Natural gas provided under a firm service contract is available to the customer at all times during the contract term and is not subject to a prior claim from another customer. For a firm service contract, the customer typically pays a facilities charge representing the customer's share of the capacity construction cost and a fixed monthly capacity reservation charge. Interruptible service contracts provide the customer with natural gas subject to the contractual rights of firm customers. The Company currently uses a combination of both firm and interruptible service to fuel its natural gas-fired generation fleet. As the percentage of natural gas use increases in terms of both energy and capacity, the Company intends to increase its use of firm transport capacity to help ensure reliability and price stability.

Pipeline deliverability can impact electrical system reliability. A physical disruption to a pipeline or compressor station can interrupt or reduce the flow pressure of gas supply to multiple EGUs at once. Electrical systems also have the ability to adversely impact pipeline reliability. The sudden loss of a large efficient generator can cause numerous smaller gas-fired CTs to be started in a short period of time. This sudden change in demand may cause drops in pipeline pressure that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric gas compressor stations, which can disrupt the fuel supply to electric generators.

As a result, the Company routinely assesses the natural gas-fueled reliability of its system. The results of these assessments show that current interruptions on any single pipeline are manageable.

But as the Company and the electric industry continue to shift to a heavier reliance on natural gas, additional actions are needed to ensure future reliability and rate stability. Additionally, equipping future gas-fired resources with backup fueling options may be needed to further enhance the reliability of the electric system.

System Planning

In general, electric transmission service providers maintain, plan, design, and construct systems that meet federally-mandated NERC Reliability Standards and other requirements, and that are capable of serving forecasted customer demands and load growth. A well-designed electrical grid, with numerous points of interconnection and facilities designed to respond to contingency conditions, results in a flexible, robust electrical delivery system.

In contrast, pipelines generally are constructed to meet new load growth. FERC does not authorize new pipeline capacity unless customers have already committed to it via firm delivery contracts, and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, in order for a pipeline to add or expand facilities, existing or new customers must request additional firm service. The resulting new pipeline capacity closely matches the requirements of the new firm capacity request. If the firm customers accept all of the gas under their respective contracts, little or no excess pipeline capacity will be available for interruptible customers. This is a major difference between natural gas pipeline infrastructure construction and electric transmission system planning—the electric system is expanded to address current or projected system conditions and the costs are typically socialized across customers.

Actions

The Company is aware of the risks associated with natural gas deliverability and has been proactive in mitigating these risks. For example, the Company continues to secure firm natural gas pipeline transportation service for all of the newer CC facilities, including the Bear Garden, Warren County, and Brunswick County Power Stations, as well as the Greensville County Power Station, which is currently under construction. As an additional example, the Company has executed a precedent agreement to secure firm transportation services on the Atlantic Coast Pipeline, which will supply natural gas to strategic points in the Company's service territory. Additionally, the Company maintains a portfolio of firm gas transportation to serve a portion of its remaining gas generation fleet.

CHAPTER 5 – FUTURE RESOURCES

5.1 FUTURE SUPPLY-SIDE RESOURCES

The Company continues to monitor and gather information about potential and emerging generation technologies from a mix of internal and external sources. The Company's internal knowledge base spans various departments including, but not limited to, planning, financial analysis, construction, operations, and business development. The dispatchable and non-dispatchable resources examined in this 2018 Plan are defined and discussed in the following subsections.

5.1.1 ASSESSMENT OF SUPPLY-SIDE RESOURCE ALTERNATIVES

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of the alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or PJM. The technology's ability to be dispatched is based on whether the resource is able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand and supply conditions. Further, the analysis of the alternative resources requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel, operation, and maintenance. Figure 5.1.1.1 summarizes the resource types that the Company reviewed as part of this IRP process. Those resources considered for further analysis in the busbar screening model are identified in the final column.

Figure 5.1.1.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource
Aero-derivative CT	Peak	Yes	Natural Gas	Yes
Batteries	Peak	Yes	Varies	No
Biomass	Baseload	Yes	Renewable	Yes
CC 1x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 2x1	Intermediate/Baseload	Yes	Natural Gas	Yes
CC 3x1	Intermediate/Baseload	Yes	Natural Gas	No
CFB	Baseload	Yes	Coal	No
Coal (SCPC) w/ CCS	Intermediate	Yes	Coal	Yes
Coal (SCPC) w/o CCS	Baseload	Yes	Coal	No
CT	Peak	Yes	Natural Gas	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes
Hydro Power	Intermittent	No	Renewable	No
IGCC CCS	Intermediate	Yes	Coal	Yes
IGCC w/o CCS	Baseload	Yes	Coal	No
Nuclear	Baseload	Yes	Uranium	Yes
Offshore Wind	Intermittent	No	Renewable	Yes
Onshore Wind	Intermittent	No	Renewable	Yes
Pumped Storage	Peak	Yes	Renewable	No
Reciprocating Engine CT	Peak	Yes	Natural Gas	No
Solar PV	Intermittent	No	Renewable	Yes
Solar PV w/Aero-derivative CT	Peak	Yes	Renewable	Yes
SMR	Baseload	Yes	Uranium	No

The resources not included as busbar resources for further analysis faced barriers such as the feasibility of the resource in the Company's service territory, the stage of technological development, and the availability of reasonable cost information. Although such resources were not considered in this 2018 Plan, the Company will continue monitoring all technologies that could best meet the energy needs of its customers.

5.1.2 DISPATCHABLE RESOURCES

Aero-derivative Combustion Turbine

Aero-derivative CT technology consists of a gas generator that has been derived from an existing aircraft engine and used in an industrial application. Designed for a small footprint and low weight using modular construction, aero-derivative CTs utilize advanced materials for high efficiency, fast start-up times with little or no cyclic life penalty. Aero-derivative CTs have been designed for quick removal and replacement, allowing for fast maintenance and greatly reduced downtimes, and resulting in high unit availability and flexibility. This is a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatch, renewable resources, such as solar and wind. This resource was considered for further analysis in the Company's busbar curve.

Batteries

Batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications. Batteries can be used to provide energy for a power station blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. Battery storage technology approximates dispatchability for these variable energy resources. The primary challenge facing battery systems is the cost. Other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. This resource was not considered for further analysis in the Company's busbar curve.

Biomass

Biomass generation facilities rely on renewable fuel in their thermal generation process. In the Company's service territory, the renewable fuel primarily used is waste wood. Greenfield biomass was considered for further analysis in the Company's busbar curve, but it was found to be uneconomic. Generally, biomass generation facilities are geographically limited by access to a fuel source.

Circulating Fluidized Bed

Circulating fluidized bed ("CFB") combustion technology is a clean coal technology that has been operational for the past few decades and can consume a wide array of coal types and qualities, including low British thermal unit ("Btu") waste coal and wood products.

The technology uses jets of air to suspend the fuel and results in a more complete chemical reaction allowing for efficient removal of many pollutants, such as NO_x and SO_2. The preferred location for this technology is within the vicinity of large quantities of waste coal. The Company will continue to track this technology and its associated economics based on site and fuel resource availability. With strict standards on emissions from the federal EGU New Source Performance Standards ("NSPS") rule along with the potential Virginia RGGI program, this resource was not considered for further analysis in the Company's busbar curve.

Coal with Carbon Capture and Sequestration[27]
Coal generating technology is very mature with hundreds of plants in operation across the United States. Carbon capture and sequestration ("CCS") is a developing technology designed to collect and trap CO_2 underground. This technology can be combined with many thermal generation technologies to reduce atmospheric carbon emissions; however, it is generally proposed to be used with coal-burning facilities. The targets for new EGUs under the federal EGU NSPS 111(b) rule, would require all new fossil fuel-fired electric generation resources to meet a strict limit for CO_2 emissions. To meet these standards, CCS technology is assumed to be required on all new coal facilities, including supercritical pulverized coal ("SCPC") and integrated-gasification combined-cycle ("IGCC") technologies. Coal generation with CCS technology, however, is still under development and not commercially available. The Company will continue to track this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve.

Fuel Cell
Fuel cells are electrochemical cells that convert chemical energy from fuel into electricity and heat. They are similar to batteries in their operation, but where batteries store energy in the components (i.e., a closed system), fuel cells consume their reactants. Although fuel cells are considered an alternative energy technology, they would only qualify as renewable in Virginia or North Carolina if powered by a renewable energy resource as defined by the respective state's statutes. This resource was considered for further analysis in the Company's busbar curve.

Gas-Fired Combined-Cycle
A natural gas-fired CC plant combines a CT and a steam turbine plant into a single, highly-efficient power plant. The Company considered CCs with heat recovery steam generators and supplemental firing capability based on commercially-available advanced technology. This resource was considered for further analysis in the Company's busbar curve.

Gas-Fired Combustion Turbine
Natural gas-fired CT technology has the lowest capital requirements ($/kW) of any resource considered; however, it has relatively high variable costs because of its low efficiency. This is a proven technology with cost information readily available. This resource was considered for further analysis in the Company's busbar curve.

IGCC with CCS[26]
IGCC plants use a gasification system to produce synthetic natural gas from coal that is then used to fuel a CC. The gasification process produces a pressurized stream of CO_2 before combustion, which, as research suggests, provides some advantages in preparing the CO_2 for CCS systems. IGCC systems remove a greater proportion of other air effluents in comparison to traditional coal units. The Company will continue to follow this technology and its associated economics. This resource was considered for further analysis in the Company's busbar curve.

Nuclear
With a need for clean, non-carbon emitting baseload power, and with nuclear power's proven record of low operating costs, around the clock availability, and zero emissions, nuclear power generation units offer a feasible alternative to the electric sector. The process for constructing a new nuclear unit remains costly and time-consuming with various permits for design, location, and operation required by various government agencies all of which add to the risk of developing a new nuclear generating unit. Recognizing the importance of nuclear power and its many environmental and economic benefits, the Company obtained a combined operating license ("COL") from the Nuclear

[27] The Company currently assumes that the captured carbon cannot be sold.

Regulatory Commission ("NRC") to support an additional unit at its existing North Anna Power Station. But based on the uncertainties of future carbon regulation, the Company has determined it is prudent to pause material development activities for North Anna 3. Going forward, the Company will continue to maintain the COL, which provides a valuable option in the future for a base load carbon-free generation resource that requires minimal land use. This resource was considered for further analysis in the Company's busbar curve.

Pumped Storage Hydroelectric Power

The Company is the operator and a 60% owner of the Bath County Pumped Storage Station, which is one of the world's largest pumped storage generation stations with a net generating capacity of 3,003 MW. Due to their size, pumped storage facilities are best suited for centralized utility-scale applications. For recent advancements on pumped storage hydroelectric power, see Section 5.4 of this 2018 Plan. This resource was not considered for further analysis in the Company's busbar curve.

Reciprocating Internal Combustion Engine

Reciprocating internal combustion engines use reciprocating motion to convert heat energy into mechanical work. Stationary reciprocating engines differ from mobile reciprocating engines in that they are not used in road vehicles or non-road equipment.

There are two basic types of stationary reciprocating engines, spark ignition and compression ignition. Spark ignition engines use a spark (across a spark plug) to ignite a compressed fuel-air mixture. Typical fuels for such engines are gasoline and natural gas. Compression ignition engines compress air to a high pressure, heating the air to the ignition temperature of the fuel, which then is injected. The high compression ratio used for compression ignition engines results in a higher efficiency than is possible with spark ignition engines. Diesel fuel oil is normally used in compression ignition engines, although some are duel-fueled (i.e., natural gas is compressed with the combustion air and diesel oil is injected at the top of the compression stroke to initiate combustion). This resource was not considered for further analysis in the Company's busbar curve.

Small Modular Reactors

Small modular reactors ("SMRs") are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured almost entirely off-site in factories and delivered and installed on site in modules. The small power output of SMRs equates to higher electricity costs than a larger reactor, but the initial costs of building the reactor are significantly reduced. An SMR entails underground placement of reactors and spent-fuel storage pools and a natural cooling feature that can continue to function in the absence of external power. SMRs have more efficient containment and lessened proliferation concerns than standard nuclear units. SMRs are still in the early stages of development and permitting. The Company will continue to monitor the industry's ongoing research and development regarding this technology. This resource was not considered for further analysis in the Company's busbar curve.

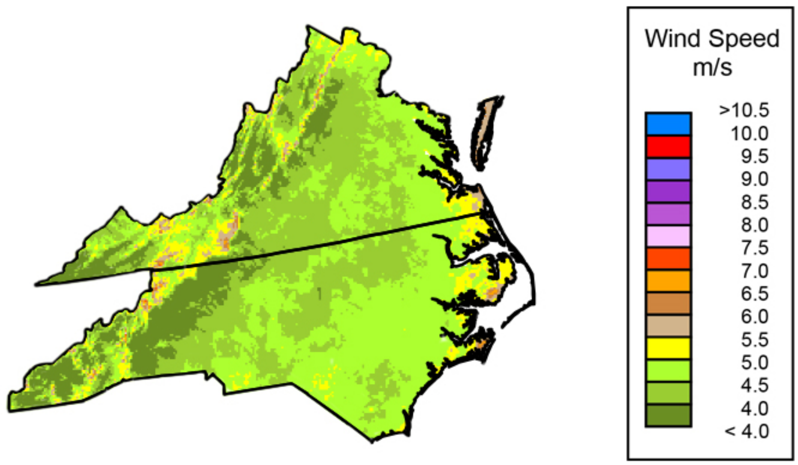
5.1.3 NON-DISPATCHABLE RESOURCES

Onshore Wind

Wind resources are one of the fastest growing resources in the United States. The Company has considered onshore wind resources as a means of meeting the RPS goals, REPS requirements, and proposed CO_2 mitigation regulations, and also as a cost-effective stand-alone resource. The suitability of this resource is highly dependent on locating an operating site that can achieve an acceptable capacity factor. Additionally, these facilities tend to operate at times that are non-coincidental with peak system conditions and therefore generally achieve a capacity contribution significantly lower than their nameplate ratings. There is limited land available in the Company's service territory to develop onshore wind resources because wind resources in the eastern portions of the United States are available in specialized locations, such as on mountain ridges. Figure

5.1.3.1 displays the onshore wind potential of Virginia and North Carolina. The Company continues to examine onshore wind and has identified three feasible sites for consideration as onshore wind facilities in the western part of Virginia on mountaintop locations. This resource was considered for further analysis in the Company's busbar curve.

Figure 5.1.3.1 - Onshore Wind Resources

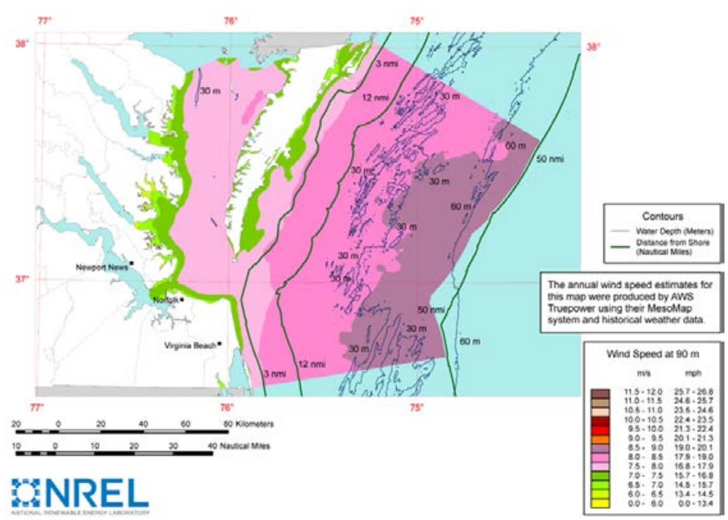


Source: National Renewable Energy Laboratory on April 2, 2018.

Offshore Wind

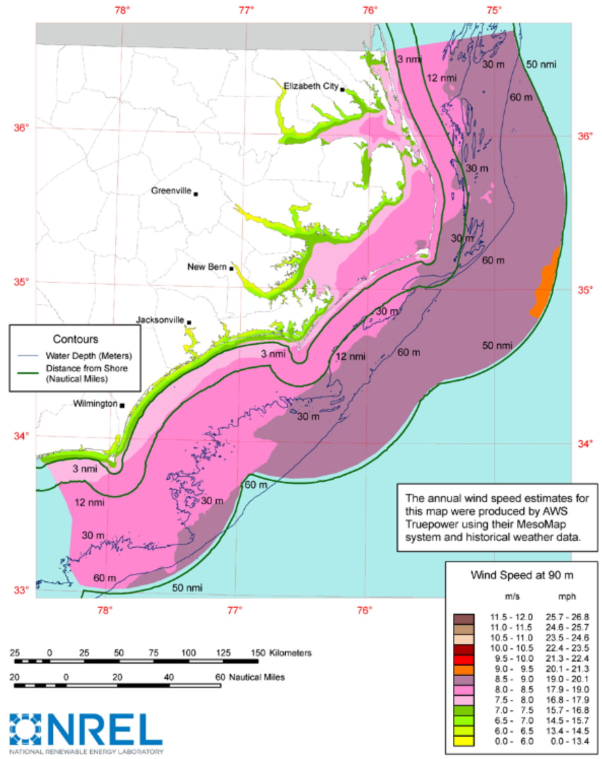
Offshore wind has the potential to provide a large, scalable renewable resource for Virginia. Figures 5.1.3.2 and 5.1.3.3 display the offshore wind potential of Virginia and North Carolina, respectively. Virginia has a unique offshore wind opportunity due to its shallow continental shelf extending approximately 40 miles off the coast, its proximity to load centers, the availability of local supply chain infrastructure, and world class port facilities. However, one challenge facing offshore wind development is its complex and costly installation and maintenance when compared to onshore wind. This resource was considered for further analysis in the Company's busbar curve.

Figure 5.1.3.2 - Offshore Wind Resources - Virginia



Source: Retrieved from U.S. Department of Energy on April 2, 2018

Figure 5.1.3.3 - Offshore Wind Resources - North Carolina

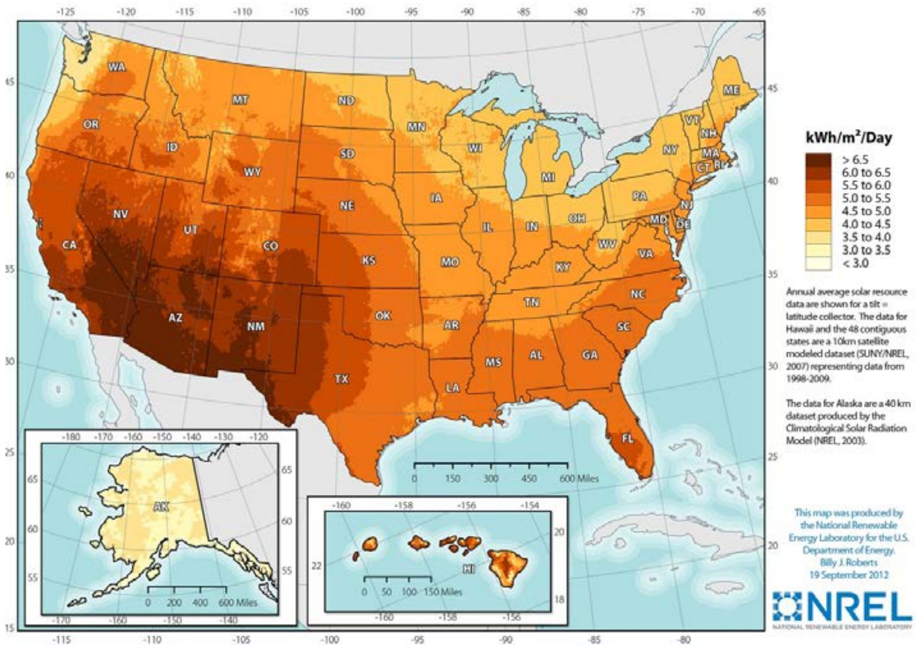


Source: Retrieved from U.S. Department of Energy on April 2, 2018.

Solar PV & Concentrating Solar Power

Solar PV and concentrating solar power ("CSP") are the two main types of solar technology used in electric power generation. Solar PV systems consist of interconnected PV cells that use semiconductor devices to convert sunlight into electricity. Solar PV technology is found in both large-scale and distributed systems and can be implemented where unobstructed access to sunlight is available. CSP systems utilize mirrors to reflect and concentrate sunlight onto receivers to convert solar energy into thermal energy that in turn produces electricity. CSP systems are generally used in large-scale solar plants and are mostly found in the southwestern area of the United States where solar resource potential is the highest. Solar PV technology was considered for further analysis in the Company's busbar curve, while CSP was not. Figure 5.1.3.4 shows the solar PV resources for the United States.

Figure 5.1.3.4 - Solar PV Resources of the United States



Source: National Renewable Energy Laboratory on April 2, 2018.

Solar generation is intermittent by nature, which fluctuates from hour-to-hour and in some cases from minute-to-minute. This type of generation volatility on a large scale could create distribution and transmission system instability. For example, Figure 5.1.3.5 shows how the solar eclipse affected the solar output at the Company's solar sites and Figure 5.1.3.6 shows the effect on aggregated solar generation and system load during the August 21, 2017 solar eclipse. Such an event demonstrates the need to observe these variable PV generation sites for reliable grid operation.

For these reasons, integration of solar PV at scale will require extensions and upgrades of the Company's supervisory control and data acquisitions system both at the transmission and distribution level. Additionally, in order to manage the added variability and uncertainty introduced by solar PV, other technologies may be needed, such as battery technology, quick start generation, voltage control technology, or pumped storage. The planning techniques and models currently used by the Company do not adequately assess the operational risk and cost that this type of generation could create, as further explained in Section 5.1.3.1.

Figure 5.1.3.5 – Solar Eclipse Effect on Solar Resources

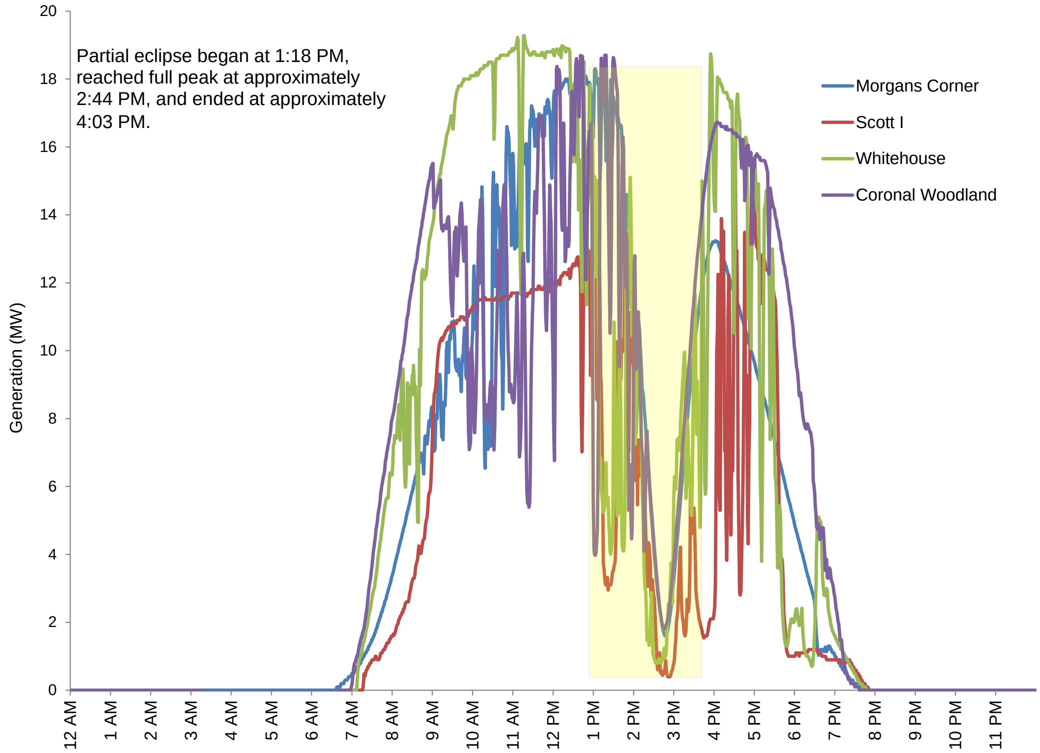
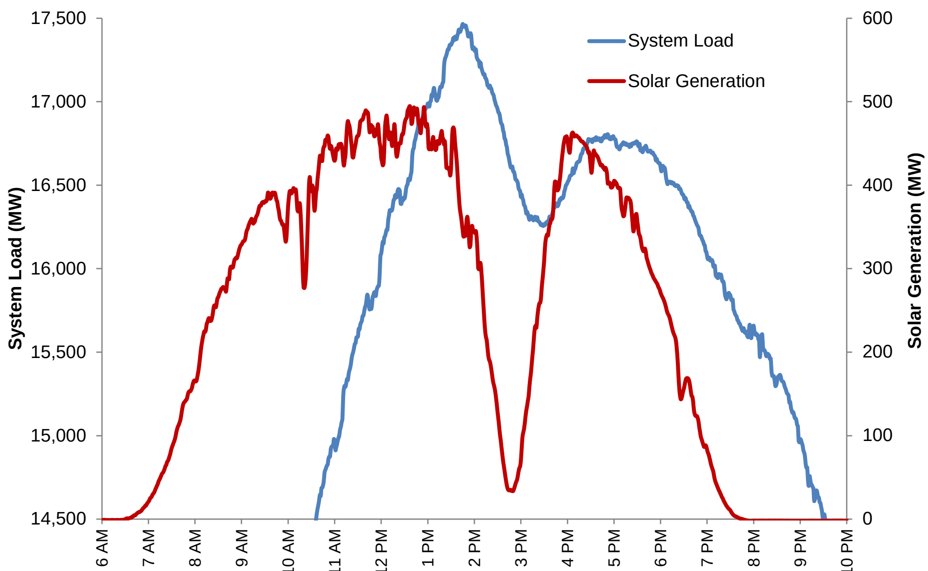


Figure 5.1.3.6 – Solar Eclipse Effect on System Load and Solar Generation



Note: The solar generation in this graph is an estimate based on the measured data available.

5.1.3.1 SOLAR PV INTEGRATION COST

The electric system reliability issues associated with the integration of large volumes of solar PV has been well documented in prior Plans. In this 2018 Plan, the Company has further refined its methods to estimate the solar PV integration costs as described below. Nevertheless, more work is required in order to fully assess the necessary grid modifications and associated costs of integrating solar PV.

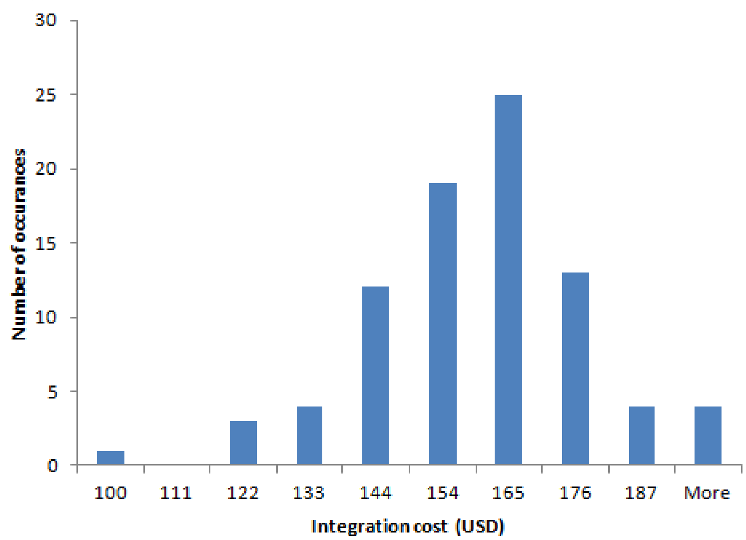
Transmission Cost

In order to assess transmission integration costs, the Company performed a steady state power flow analysis using a scenario where 7,000 MW of solar PV was interconnected to the Company's transmission grid. In the 2017 Plan, this analysis was conducted by utilizing the most optimal locations for siting solar PV generation in terms of cost. In this 2018 Plan, however, the 7,000 MW of solar PV were sited based on a random site selection process described below.

Like the analysis included in the 2017 Plan, the Company first identified a population of solar PV sites based on available land parcels in Virginia that were screened utilizing several criteria, including access to the Company's transmission grid and other land characteristics along with cost. This data was then combined with solar irradiance data provided by National Renewable Energy Laboratory ("NREL") in order to assess the solar generation potential of the specific sites. From this screening process, 326 solar PV sites were identified that represented approximately 37 GW (nameplate) of solar PV generation. Then 100 cases were created by randomly selecting feasible sites from the pre-screened set of 326 sites. Each selected case included approximately 7,000 MW (nameplate) of solar PV capacity.

Next, using the PSS®E power flow model, the 100 different solar cases were assessed under 2019 PJM summer peak demand conditions, while assuming maximum solar PV generation output (with reactive power support of +/- 0.95 power factor), and displacement of generation from other Company-owned facilities. The results of a majority of these modeling cases identified several low voltage and thermal violations that would require mitigation activities via physical enhancements to the Company's transmission system. The total integration costs were then evaluated by including the cost of these enhancements with other required system interconnection costs. The results of this stochastic analysis are reflected in the total integration cost (interconnection plus transmission improvements) frequency distribution shown in Figure 5.1.3.1.1. Based on this analysis, the expected value of the total integration cost is approximately $165.00/kW.

Figure 5.1.3.1.1 - Solar PV Integration Cost Histogram



The Company plans to build on this work in future Plans by considering dynamic system conditions arising out of sudden changes to solar PV output. Also, the Company intends to assess levels of solar PV that are higher and lower than the 7,000 MW in future Plans.

Distribution Cost
For purposes of this 2018 Plan, the Company utilized actual interconnection costs associated with solar PV facilities interconnected to the Company's distribution network. This integration cost was derived from the system impact studies performed using the Company's distribution network model under the relevant state jurisdictional generation interconnection process. The average actual interconnection cost of these solar PV facilities is approximately $133.00/kW.

Total Interconnection Cost
Going forward, it is not reasonable to assume that 100% of future solar PV additions to the Company's system will be interconnected solely at the transmission level or distribution level. For purposes of this 2018 Plan, the Company assumed that 70% of all future solar PV additions would be interconnected along the Company's transmission network, while 30% would be interconnected at the distribution level. These weighting factors were selected based on current solar PV facilities interconnected to the Company's network, along with solar PV facilities to be located in the Company's service territory that are listed in the PJM and state interconnection queues. A 70/30 weight results in an average interconnection cost of $155.00/kW.

As noted above, the interconnection cost for solar PV along the Company's transmission network ($165.00/kW) is based on 7,000 MW (nameplate) of solar PV generation. In the Company's judgment, however, it is unlikely that the same interconnection cost will be applicable for solar PV levels that are higher or lower than the 7,000 MW (nameplate) that was evaluated. Therefore, for purposes of this 2018 Plan, the Company used the interconnection cost schedule as listed in Figure 5.1.3.1.2 for modeling various nameplate levels of solar PV.

Figure 5.1.3.1.2 – Solar PV Interconnection Cost Schedule

From	Through	Interconnection Cost
0 MW	2,560 MW	$75/kW
2,561 MW	4,960 MW	$115/kW
4,961 MW	6,960 MW	$155/kW

Generation Costs
Re-dispatch generation costs are defined in this 2018 Plan as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. Historically, these types of events were driven by load variations due to actual weather that differs from what was forecasted for the period in question. For example, most power system operators assess the generation needs for a future period, typically the next day, based on load forecasts and commit a series of generators to be available for operation in that period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, however, actual load may vary from what was planned and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional costs, due to real time variability, are known as re-dispatch costs.

As more and more intermittent generation like solar PV or wind is added to the grid, additional uncertainty about re-dispatch costs is added due to unpredictable cloud cover or changes in wind speed. In order to assess the resulting re-dispatch costs, the Company performed a simulation analysis to determine the impact on generation operations at varying levels of solar PV penetration. To study the effects of these intermittent resources, hourly generation data from 26 individual sites was used to develop generation profiles from actual solar PV facilities currently interconnected to the Company's system. The study was performed at three different levels of solar penetration (up to 4,000 MW) to provide a range of results. The total system costs from each of these runs were compared to one another using several different mathematical average variances.

Relative to last year's study, several improvements were made to the process and data analyzed. First, the PLEXOS model was used for the production cost runs, which was able to incorporate an 8,760 hourly load profile for each of the solar sites studied. This is an improvement from the Strategist methodology used in the 2017 Plan, which incorporated a "typical day by month" load profile. Second, the dispatch from the PLEXOS model utilized the short-term ("ST") module, which was able to include dispatch constraints on thermal generating units such as ramp rates, minimum up and down times, and other constraints that were not considered in the previous year's modeling. The ST module better represents the strains put on a generating system by intermittent resources. Finally, the overall sample size used for the study has increased in both breadth and depth. Last year's generation study pulled from 9 sites that totaled approximately 76 MW. This year's study pulled from 26 sites that totaled approximately 220 MW. In this same regard, the geographic diversity in this year's study is greater, as several utility scale sites located in Virginia have a full year of operating data. There were also a greater number of horizontal tracker sites that have a full year of operational data for this year's study; last year's sample was made up of mostly smaller rooftop or fixed tilt projects.

The levelized cost differential between each of the cases resulted in an approximate re-dispatch cost of $1.78/MWh. This value was used as a variable cost adder for all solar PV generation evaluated in this 2018 Plan.

As noted above, this analysis incorporated the hourly modeling feature available in the PLEXOS model. The Company is using the feature along with similar features in its AURORA model in order to examine the issues created by intermittent generation in a more robust manner. The Company is currently using this hourly feature and sub-hourly features contained in PLEXOS and AURORA to better examine and value of electricity storage, and other fast ramping resources such as aero-derivative turbines. The Company intends to incorporate the results of these studies in future Plans.

Limitations of the Solar Integration Cost Analysis

While this 2018 Plan further refines solar PV integration costs as described above, it is important to note that such costs are limited to the scope of the analysis conducted. For example, the transmission integration costs described above are assessed under steady-state conditions. Under dynamic conditions, it is highly likely that the integration costs will also be different. The same likelihood applies at the distribution level. Furthermore, although the distribution integration costs described above are based on actual interconnection cost data, that data does not include distribution substation upgrade costs that may be necessary to support a high influx of solar PV integration at the distribution level. Nor does it include transmission upgrade cost to the extent solar PV generation at the distribution level back-feeds onto the transmission grid.

From a generation perspective, the costs described above are only intended to assess re-dispatch costs. The costs associated with additional spinning reserve to support variable output from solar PV and the additional cost of machine wear and tear resulting from increased cycling have not yet been evaluated by the Company. The Company continues to develop processes that will aid in the cost evaluation associated with solar PV integration. The results of these evaluations will be included in future Plans filed by the Company.

Another major assumption used by the Company in this 2018 Plan is that the majority (70%) of future solar PV facilities would be interconnected at the transmission level. The Company maintains that this assumption is reasonable given current available information, including the economies of scale associated with large solar PV facilities. But if solar PV costs continue to decline, and given customer and society's preference for clean reliable energy, it is not unreasonable to expect that a large percentage of new solar PV facilities will be installed at or near customer homes and businesses or at other locations along the Company's distribution network. Given this plausible future outcome, the Company's distribution grid will require significant modification in order to maintain reliable service to its customers. This is one of the driving forces behind the GTSA signed into Virginia law. A high-level summary of the Company's grid modernization plan is reflected in Section 5.1.4.

Finally, for purposes of this 2018 Plan, the Company has placed an annual 480 MW (nameplate) limitation with respect to the level of solar PV generation that can achieve commercial operation in any given year. The Company's ability to develop and bring online multiple solar PV facilities annually is limited due to the schedules associated with land access, permitting, equipment procurement, and regulatory approvals.

Distribution Feeder Hosting Capacity Analysis
As part of this 2018 Plan, the Company has developed a process to identify PV hosting capacity at the distribution feeder level.

Typically, circuits and substations near load centers such as Northern Virginia have the capacity to integrate high levels of distributed generation such as solar PV. However, land availability in these regions can be low. Therefore, the analysis was performed based on prospective land for solar PV project development within close proximity to the Company's distribution facilities. Prospective locations and sizes of solar PV sites were chosen by the land data provided by the Company's GIS system. The land data was provided at one meter resolution and land parcels characterized by pasture, hay, and cultivated crops were considered as possible solar sites.

The initial step was to identify distribution level feeders with three phase (greater than or equal to 12.5 kV), within a quarter mile of the land parcels sized 40 acres (based on 8 acres per MW) and greater. This resulted in 412 feeders in Virginia. Next, additional feeders were eliminated due to voltage rise greater than 3% with 5 MW connected at unity power factor. Circuits that already had significant solar resources behind the step-down transformers and line regulators were eliminated as well.

Each remaining feeder was then evaluated to determine the maximum amount of PV that could be connected based on the nearest parcels. Some other filtering criteria were that the voltage must not rise more than 3%, no equipment rating could be exceeded, and substation transformer only loaded to 70% of nameplate at no load scenario on the feeder. This resulted in 529 sites on 303 feeders, 221 substation transformers, and 160 substations. These identified feeders can support approximately 4,200 MW of solar based on the substation transformers' loading capacity. Virtually every circuit will need station regulators added or upgraded to keep voltage within acceptable ranges. Additional PV hosting capacity could be accommodated by re-conductoring, substation transformer upgrades, or operating PV inverters on a leading power factor. It should be acknowledged that this analysis did not consider the aggregate effect of the distributed solar PV on to the transmission grid. As new DG projects are interconnected to the Company's distribution system, or as the distribution system is modified, hosting capacity will change. This analysis was conducted to identify the overall capacity of the Company's current distribution system to address future solar PV development.

5.1.4 GRID MODERNIZATION

The Company recognizes that customer expectations are evolving and that service reliability improvements will be required to maintain reliability, address resilience, enhance physical and cyber security, and improve the overall customer experience. The grid must adapt in order to meet these expectations.

As stated earlier in this 2018 Plan, utility-scale solar continues to be cost competitive with other more traditional forms of generation. The anticipated proliferation of smaller-scale DERs includes renewable resources, such as solar and wind, and battery technology. As costs continue to decline, it is not unreasonable to expect that the Company or its customers will continue to install solar or other DERs at their homes, businesses, or other locations along the Company's distribution network.

Like most of the industry, the Company's electric distribution system was designed for "one-way" delivery of energy to meet peak demand—from the generator, to the transmission network, to the distribution network, and then to the customer meter.

To the extent that DER proliferation and the adoption of EVs and battery storage continues, the Company must be prepared to meet a new paradigm that will require the Company to transform its existing electric delivery from its original one-way design to a modern two-way network capable of facilitating instantaneous energy injections and withdrawals at any point along the network while continuing to maintain the highest level of reliability and while maintaining service levels that customers expect and deserve. The first step in this transformation process is a modernization of the distribution grid.

To that end, the Company has begun the initial planning associated with a transformational grid modernization effort. The modernized system would need to include elements such as (i) "smart" or AMI meters; (ii) improved communications network; (iii) intelligent devices to monitor, predict and control the grid; (iv) distribution substation automation; (v) replace aging infrastructure; (vi) improvements to security; vii) methods to investigate new innovative technologies; and (viii) an enhanced customer information platform to enable management of customers' energy usage.

Currently, at the generation and transmission level, the Company's electric system operators possess real-time visibility, communications, and control. Implementing a sophisticated system of communication and control similar to what system operators currently utilize at the generation and transmission levels will not only improve and modernize the distribution grid, but will make it adaptable to evolving technological changes.

In a future where potentially tens of thousands of DER devices are located at homes or businesses throughout Virginia, system operators will need the ability to monitor these devices in order to operate the distribution network so that overall electric service reliability can be safely and efficiently maintained. In addition to ensuring reliability and accommodating integration of distributed generation into the grid, this modernization program will offer customers a new information platform and opportunities to manage their energy usage. The Company continues to assess the details and costs associated with developing a future distribution grid that is stronger, smarter, and greener than today's network. The Company intends to report those findings in future Plans.

5.1.5 THIRD-PARTY MARKET ALTERNATIVES TO CAPACITY RESOURCES

Solar

During the last several years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territories. In July 2015, the Company issued an RFP for new utility-scale solar PV generating facilities located in Virginia. As a result of this RFP, the Company contracted with two developers for approximately 40 MW (nameplate) of solar. Since then, the developer of one of the 20 MW solar facilities failed to obtain a permit and terminated the PPA; the other PPA came online in December 2017. During this same timeframe, the Company brought online three self-build solar facilities (Scott, Whitehouse, and Woodland) totaling approximately 56 MW (nameplate).

In 2017, the Company issued three solicitations that included requests for solar generation. The first solicitation was a request for information ("RFI") for renewable resources to potentially serve customers interested in being served by 100% renewable resources on a continuous hourly basis. The second solicitation was an RFP for the Company's Community Solar Pilot Program seeking small solar resources (2 MW or less) totaling 10 MW. The third solicitation was an RFP for approximately 300 MW of solar and onshore wind generation located in Virginia. The Company received a number of solar proposals through the RFI, but has yet to contract with any of those resources pending a decision from the SCC on the Company's application for 100% renewable energy tariffs in Case Nos. PUR-2017-00060 and PUR-2017-00157. Both RFPs attracted considerable interest from solar developers. The Company continues to evaluate responses to the RFP for the Community Solar Pilot Program and expects to contract with resources from that solicitation in 2018, pending approval of the Company's Community Solar application before the SCC in Case No. PUR-2018-00009. Finally, the Company continues to evaluate responses to the RFP for approximately 300 MW of solar and onshore wind generation and expects to make a decision on those proposals in 2018.

In North Carolina, over the same period, the Company has signed 83 PPAs totaling approximately 570 MW (nameplate) of new solar NUGs. Of these, 479 MW (nameplate) are from 67 solar projects that were in operation as of March 2018. The majority of these developers are qualifying facilities, contracting to sell capacity and energy at the Company's published North Carolina Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act ("PURPA"), as approved in Docket No. E-100, Sub 136 (2012), Docket No. E-100, Sub 140 (2014), and Docket No. E-100, Sub 148 (2016). Going forward, the Company's qualifying facility PPAs will reflect the amended provisions of NCGS § 62-156, as enacted by North Carolina House Bill 589, governing payments for avoided capacity and for PURPA contract availability and terms.

Wind

The Company received several proposals for wind generation resources in PJM through the RFI mentioned above. The Company has yet to contract with any of these resources pending a decision on its tariff application. The Company received one wind proposal through its RFP for approximately 300 MW of solar and onshore wind generation. The proposal's price was not competitive when compared with other solar alternatives.

Other Third-Party Alternatives

Over the past two years, the Company has evaluated a number of opportunities to extend the terms of the current NUG contracts that have recently expired or will expire in the next several years. Many of these were evaluated through a formal RFP process, while others were evaluated through direct contact with the existing NUG owner. However, none of these existing NUGs were found to be cost-effective options for customers when compared to other options. Additionally, the Company has been in early discussions with a number of developers of other new third-party generation alternatives over the past year. However, none of these discussions have matured to the point of the Company receiving or being able to evaluate a firm PPA price offer.

In 2017, one of the Company's NUGs, Roanoke Valley Facility I and II, ceased operations, but the amended agreement called for replacement power equal to the previously contracted amounts to be provided to the Company through the term of the original NUG contract, ending in March 2019. While the Roanoke Valley Facility is no longer listed as a NUG in Appendix 3B, the Company's future resource planning includes the replacement power through the term of this agreement.

5.2 LEVELIZED BUSBAR COSTS

The Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include: fuel, heat rate, emissions, variable and fixed O&M costs, expected service life, and overnight construction costs.

Figures 5.2.1 and 5.2.2 display summary results of the busbar model comparing the economics of the different technologies discussed in Sections 5.1.2 and 5.1.3. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources for the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

Figure 5.2.1 - Dispatchable Levelized Busbar Costs (2023 COD)

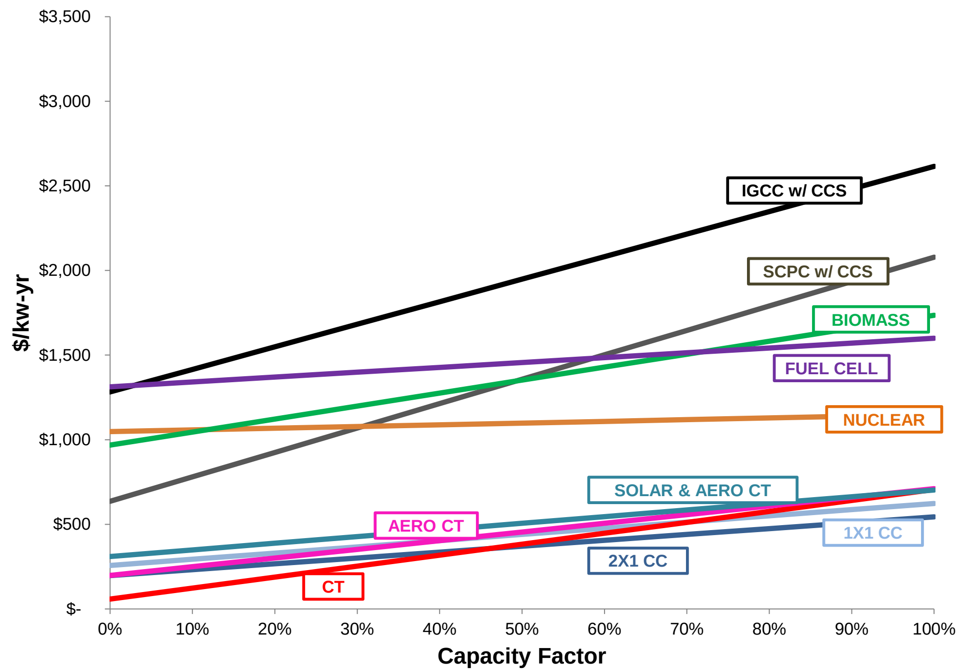
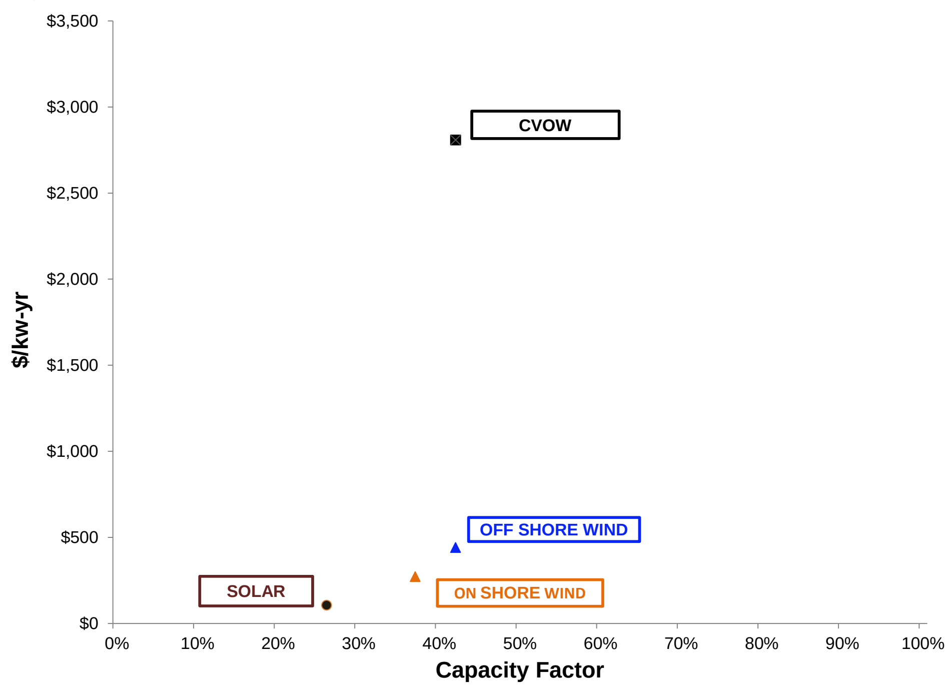


Figure 5.2.2 - Non-Dispatchable Levelized Busbar Costs (2023 COD)



Appendix 5A contains the tabular results of the screening level analysis. Appendix 5B displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated 2018 real dollar construction costs.

In Figure 5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with busbar costs above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher cost generation, however, may be necessary to achieve other constraints like those required by potential carbon regulation. Figures 5.2.1 and 5.2.2 allow comparative evaluation of resource types. The cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of operating the unit, including fuel, emissions, and any REC or production tax credit ("PTC") value a given unit may receive.

As shown in Figure 5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 25% for meeting the Company's peaking requirements. The CC 2x1 technology is the most economical option for capacity factors greater than approximately 25%. Also, as depicted in Figure 5.2.2, solar PV is a competitive choice at capacity factors of approximately 25%.

Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods, therefore more capacity would be required to maintain the same level of system reliability. For example, onshore wind provides only 13% of its nameplate capacity as firm capacity that is available to meet the Company's PJM resource requirements as described in Chapter 4. Figure 5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability. The Company is routinely updating and evaluating the costs and availability of renewable resources.

Figure 5.2.3 identifies some basic capacity and energy differences between dispatchable resources and non-dispatchable resources. One additional factor to consider for solar installation is the amount of land required. For example, the installation of 1,000 MW of solar requires approximately 8,000 acres of land, which would encompass 12.5 square miles.

Figure 5.2.3 - Comparison of Resources by Capacity and Annual Energy

Resource Type	Nameplate Capacity (MW)	Estimated Firm Capacity (MW)	Estimated Capacity Factor (%)	Estimated Annual Energy (MWh)
Onshore Wind	1,000	130	37%	3,241,200
Offshore Wind	1,000	167	42%	3,635,400
Solar PV	1,000	229	26%	2,277,600
Nuclear	1,000	1,000	92%	8,059,200
CC	1,000	1,000	80%	7,008,000
CT	1,000	1,000	20%	1,752,000

Note: 1) Solar PV firm capacity has 22.86% value through 35 years of operation.

The assessment of alternative resource types and the busbar screening process provides a simplified foundation in selecting resources for further analysis. However, the busbar curve is static in nature because it relies on an average of all of the cost data of a resource over its lifetime. Further analysis was conducted in PLEXOS to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matched the resources found to be cost-effective in this screening process. This PLEXOS simulation analysis further refines the Company's analysis and assists in selecting the type and timing of additional resources that economically fit the customers' current and future needs.

5.3 GENERATION UNDER DEVELOPMENT

Extension of Nuclear Licensing

An application for a subsequent or second license renewal is allowed during a nuclear plant's first period of extended operation — i.e., in the 40 to 60 years range of its service life. Surry Units 1 and 2 entered into that period in 2012 (Unit 1) and 2013 (Unit 2). North Anna Units 1 and 2 will enter into that period in 2018 (Unit 1) and 2020 (Unit 2).

The Company informed the NRC in a letter dated November 5, 2015, of its intent to submit a subsequent license renewal application for Surry Power Station Units 1 and 2. Under the current schedule, the Company intends to submit an application for the second renewed Operating Licenses in accordance with 10 CFR Part 54 by the end of the first quarter of 2019. The issuance of the renewed license would follow successful NRC safety and environmental reviews tentatively in the 2022 timeframe.

The Company informed the NRC in a letter dated November 9, 2017, of its intent to submit a subsequent license renewal application for North Anna Power Station Units 1 and 2. Under the current schedule, the Company intends to submit an application for the second renewed Operating Licenses in accordance with 10 CFR Part 54 by the end of the 2020. The issuance of the renewed license would follow successful NRC safety and environmental reviews tentatively in the 2023 timeframe.

There has been no additional correspondence between the Company and the NRC concerning any second license renewals since November 2017. The Company has, however, participated in public industry meetings during the last 12 months with other potential utility applicants in which second license renewal applications have been discussed with the NRC.

NRC draft guidance on the requirements for a second license renewal was issued for public comment in December 2015. The industry, including the Company and interested stakeholders, has reviewed the guidance information to understand the pre-decisional technical requirements and additional aging management program requirements. The nuclear industry, including the Company, provided comments through the Nuclear Energy Institute in February 2016, which was the end of the public comment period. The NRC is currently evaluating the industry and stakeholder comments. Following the issuance of the final NRC guidance documents, the Company will begin finalizing the technical evaluation and additional aging management program requirements required to support the second license renewal application.

The preliminary cost estimates for the extension of the nuclear licenses for Surry Units 1 and 2, as well as North Anna Units 1 and 2 can be found in Appendix 5F.

Solar

US-3 Solar 1, 142 MW (nameplate), and US-3 Solar 2, 98 MW (nameplate), are Company-owned Virginia utility-scale solar generation currently under development. These two projects are included in the 2018 Plan.

Offshore Wind

The Company continues to pursue offshore wind development in a prudent manner for its customers and for the state's economic development. Offshore wind has the potential to provide a scalable renewable resource if it can be achieved at reasonable cost to customers. To help determine how this can be accomplished, the Company is involved in two active projects: (i) CVOW and (ii) commercial development in the Virginia Wind Energy Area ("WEA"), both of which are located approximately 27 miles (approximately 24 nautical miles) off the coast of Virginia. A complete discussion of these efforts is included in Section 5.4.

Figure 5.3.1 and Appendix 5C provide the projected in-service dates and capacities for generation resources under development for the Alternative Plans.

Figure 5.3.1 - Generation under Development[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Capacity (Net MW)	
						Summer	Winter
2020	US-3 Solar 1	VA	Solar	Intermittent	142	33	33
2021	CVOW	VA	Wind	Intermittent	12	2	2
2021	US-3 Solar 2	VA	Solar	Intermittent	98	22	22
2032	Surry Unit 1 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
2033	Surry Unit 2 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
2038	North Anna Unit 1 Nuclear Extension	VA	Nuclear	Baseload	838	838	868
2040	North Anna Unit 2 Nuclear Extension	VA	Nuclear	Baseload	834	834	863

Notes: 1) All Generation under development projects and capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approval.

5.4 EMERGING AND RENEWABLE ENERGY TECHNOLOGY DEVELOPMENT

The Company conducts research in the renewable and alternative energy technologies sector, participates in federal and state policy development on alternative energy initiatives, and identifies potential alternative energy resource and technology opportunities within the existing regulatory framework for the Company's service territory. The Company is actively pursuing the following technologies and opportunities.

Research and Development Initiatives – Virginia

Pursuant to Va. Code § 56-585.2, utilities that are participating in Virginia's RPS program are allowed to meet up to 20% of their annual RPS goals using RECs issued by the SCC for investments in renewable and alternative energy research and development activities. In addition to three projects completed in 2014, the Company is currently partnering with nine institutions of higher education on Virginia renewable energy research and development projects. The Company filed its annual report in November 2017, analyzing the prior year's PJM REC prices and quantifying its qualified investments to facilitate the SCC's validation and issuance of RECs for Virginia renewable and alternative energy research and development projects.

Research and Development Initiatives – North Carolina

Pursuant to NCGS § 62-133.8(h), the Company completed construction of its microgrid demonstration project at its North Carolina Kitty Hawk District Office in July 2014. The microgrid project included innovative distributed renewable generation and energy storage technologies. A microgrid, as defined by the DOE, is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid, allowing it to operate in grid-connected or island mode. The project included four different types of micro-wind turbines, a solar PV array, and a lithium-ion battery integrated behind-the-meter with the existing on-site diesel generator and utility feed. In the third quarter of 2015, the Company integrated two small, residential-sized fuel cells in order to study the fuel cell's interaction with the on-site renewable energy technologies in a microgrid environment. The knowledge gained from this microgrid project has been used to further assess the best practice for integrating large amounts of intermittent generation (such as wind and solar PV) into the existing grid.

Offshore Wind – Virginia
The Company is actively participating in offshore wind policy and innovative technology development in order to identify ways to advance offshore wind generation responsibly and cost-effectively. The Virginia General Assembly passed legislation in 2010 to create the Virginia Offshore Wind Development Authority ("VOWDA") to help facilitate offshore wind energy development in the Commonwealth. The Company continues to actively participate in VOWDA, as well as the Virginia Offshore Wind Coalition ("VOW"). The VOW is an organization comprised of developers, manufacturers, utilities, municipalities, businesses, and other parties interested in offshore wind. This group advocates on the behalf of offshore wind development before the Virginia General Assembly and with the Virginia delegation to the U.S. Congress.

As part of its ongoing commitment to bring cleaner energy to its customers, the Company is moving forward on the Mid-Atlantic's first offshore wind project in a federal lease area. In July 2017, the Company announced that it had signed an agreement and strategic partnership with Ørsted Energy of Denmark, a global leader in offshore wind development, to build two 6 MW turbines off the coast of Virginia Beach. The Company remains the sole owner of the project.

In January 2018, an engineering, procurement, and construction ("EPC") agreement was executed with Ørsted and development work on CVOW is ongoing to support a targeted installation by the end of 2020, with capacity being available in the 2021 RPM auction. The project is an important first step toward offshore wind development for Virginia and the United States. Along with clean energy, it will provide the Company valuable experience in permitting, constructing, and operating offshore wind resources which will help inform potential commercial scale development of the adjacent 112,000 acre wind lease area.

Energy Storage Technologies
There are several different types of energy storage technologies. Energy storage technologies include, but are not limited to, pumped storage hydroelectric power, superconducting magnetic energy storage, capacitors, compressed air energy storage, flywheels, and batteries. Cost considerations and technology maturity have restricted widespread deployment of most of these technologies, with the exception of pumped storage hydroelectric power and batteries.

There is also increasing interest in pumped storage hydroelectric power as a storage mechanism for the intermittent and highly variable output of renewable energy sources such as solar and wind. For example, the 2017 Regular Session of the Virginia General Assembly passed Senate Bill 1418 ("SB 1418") supporting construction of "one or more pumped hydroelectric generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are located in the coalfield region of the Commonwealth." The General Assembly adopted the Governor's amendments to SB 1418 on April 5, 2017. The bill became law effective July 1, 2017.

Following the approval of SB 1418, the Company is in the early stages of conducting feasibility studies for a potential pumped storage facility in the western part of the Commonwealth of Virginia. The Company acknowledges that pumped storage is a proven dispatchable technology that would complement the ongoing integration of renewable solar and wind resources.

In addition to pumped storage hydroelectric power, the Company continues to monitor advancements in other energy storage technologies, such as batteries and flywheels. These energy storage technologies can also be used to provide grid stability as more renewable generation sources are integrated into the grid. In addition to reducing the intermittency of wind and solar generation resources, batteries can shift power output from periods of low demand to periods of peak demand. This increases the dispatchability and flexibility of these resources.

Electric Vehicle Initiatives
Various automotive original equipment manufacturers ("OEMs") have released EVs for sale to the public in the Company's service territory. The Company continues to monitor the introduction of EV models from several other OEMs in its Virginia service territory. While the overall penetration of EVs has been somewhat lower than anticipated, recent registration data from the Virginia Department of Motor Vehicles ("DMV") and IHS, Inc. ("IHS", formerly Polk Automotive), demonstrates steady growth. The Company did not augment its load forecast used in this 2018 Plan to account for additional load from EVs. Therefore, only incremental load from EVs that is imbedded in history is partially included in the load forecast used in the 2018 Plan.

5.5 FUTURE DSM INITIATIVES
In 2016, the Company conducted a residential appliance saturation survey with results shown in Figure 5.5.1. All else equal, the reduction in average energy use per household would be expected to reduce the technical, economic, and achievable potential savings. Lower consumption means that there is less opportunity for energy savings. However, the "all else equal" caveat is an important one because factors that change the economics of individual DSM measures also affect potential, and possibly offset the impacts of consumption trends. Such factors include changes to avoided costs (which can change the cost effectiveness of a measure from a societal standpoint), rates (which can change the cost effectiveness of a measure from the customer standpoint), and measure costs (which can affect both). The introduction of new technologies can also increase potential in the long run. On the other hand, codes and standards tend to reduce the achievable potential available to programs by improving the efficiency of baseline equipment or homes. In these situations, society captures the savings, but through a separate avenue from efficiency programs.

Figure 5.5.1 – Residential Energy Intensities (average kWh over all households)

	Virginia (2013)			Virginia (2016)			Percent Change
kWh/household	Single Family	Multi-family	All Homes	Single Family	Multi-family	All Homes	All Homes
Base Split-System Air Conditioner	1,557	621	1,398	1,346	666	1,230	-12%
Base Early Replacement Split-System Air Conditioner	325	130	292	470	122	411	41%
Base Heat Pump Cooling	1,321	667	1,211	997	687	944	-22%
Base Early Replacement Heat Pump Cooling	201	120	187	203	49	177	-5%
Base Room Air Conditioner	91	35	81	54	55	54	-33%
Base Early Replacement Room Air Conditioner	17	3	15	4	0	3	-80%
Base Dehumidifier	17	8	15	287	38	245	1533%
Base Furnace Fans	1,058	458	956	1,085	442	976	2%
Base Heat Pump Space Heating	1,344	581	1,215	1,527	610	1,372	13%
Base Early Replacement Heat Pump Heating	339	139	305	358	118	317	4%
Base Resistance Space Heating	656	600	647	376	348	372	-43%
Base High-Efficiency Incandescent Lighting, 0.5 hrs/day	151	67	137	93	46	85	-35%
Base High-Efficiency Incandescent Lighting, 2.5 hrs/day	590	279	537	332	164	304	-41%
Base High-Efficiency Incandescent Lighting, 6 hrs/day	399	174	361	190	115	177	-46%
Base Lighting 15 Watt CFL, 0.5 hrs/day	20	9	18	17	10	16	-11%
Base Lighting 15 Watt CFL, 2.5 hrs/day	82	37	74	70	40	65	-12%
Base Lighting 15 Watt CFL, 6 hrs/day	54	25	49	46	27	43	-12%
Base Lighting 9 Watt LED, 0.5 hrs/day	1	1	1	3	3	3	200%
Base Lighting 9 Watt LED, 2.5 hrs/day	10	6	10	24	17	23	130%
Base Lighting 9 Watt LED, 6 hrs/day	10	5	9	23	8	20	122%
Base Specialty Incandescent Lighting, 0.5 hrs/day	64	21	57	79	24	69	21%
Base Specialty Incandescent Lighting, 2.5 hrs/day	266	85	236	323	98	285	21%
Base Specialty Incandescent Lighting, 6 hrs/day	176	58	156	213	67	189	21%
Base Fluorescent Fixture 1.8 hrs/day	442	135	390	442	121	388	-1%
Base Refrigerator	563	395	535	582	438	557	4%
Base Early Replacement Refrigerator	80	54	75	200	126	187	149%
Base Second Refrigerator	352	6	293	405	23	340	16%
Base Freezer	334	52	286	150	63	136	-52%
Base Early Replacement Freezer	59	9	51	110	21	95	86%
Base Second Freezer	18	0	15	14	0	11	-27%
Base 40 gal. Water Heating	1,569	1,441	1,547	920	261	808	-48%
Base Early Replacement Water Heating	277	254	273	1,071	1,176	1,089	299%
Base Clothes washer	43	25	40	44	35	43	8%
Base Clothes Dryer	600	469	578	691	570	670	16%
Base Dishwasher	202	152	194	221	180	214	10%
Base Pool Pump	158	0	131	45	0	37	-72%
Base Plasma TV	77	34	70	35	24	33	-53%
Base LCD TV	180	103	167	185	104	171	2%
Base CRT TV	59	31	54	9	6	8	-85%
Base Set-Top Box	221	102	201	221	144	208	3%
Base DVD Player	26	17	25	31	17	29	16%
Base Desktop PC	241	128	222	274	107	245	10%
Base Laptop PC	43	26	40	53	37	51	28%
Base Cooking	528	451	515	659	617	652	27%
Base Miscellaneous	600	500	583	600	500	583	0%
Whole House	15,420	8,516	14,252	15,083	8,330	13,940	-2%

The Company conducted a DSM market potential study in 2017 ("2017 DSM Potential Study"), with results illustrated in Figure 5.5.2. The 2017 DSM Potential Study identified the technical, economic, and achievable market potential of energy savings for all measures in the Company's residential and commercial sectors. The technical market potential reflects the upper limit of energy savings assuming anything that could be achieved is realized. Similarly, the economic potential reflects the upper limit of energy savings potential from all cost-effective measures. The achievable potential reflects a more realistic assessment of energy savings by considering what measures can be cost-effectively implemented through a future program. The result is a list of cost-effective measures that can ultimately be evaluated for use in future program designs and a high level estimate of the amount of energy and capacity savings still available in the Company's service territory. The achievable potential identified in the 2017 DSM Potential Study is shown in Figure 5.5.2.

Figure 5.5.2 – 2018 Plan vs. DSM System Achievable Market Potential

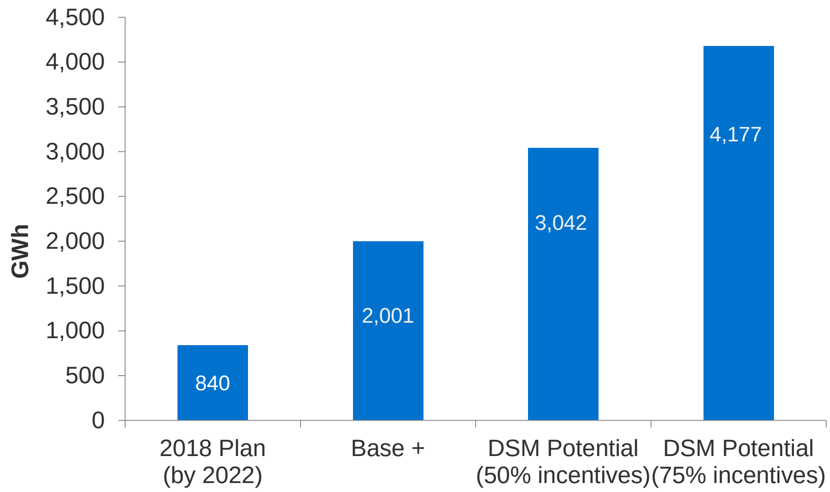
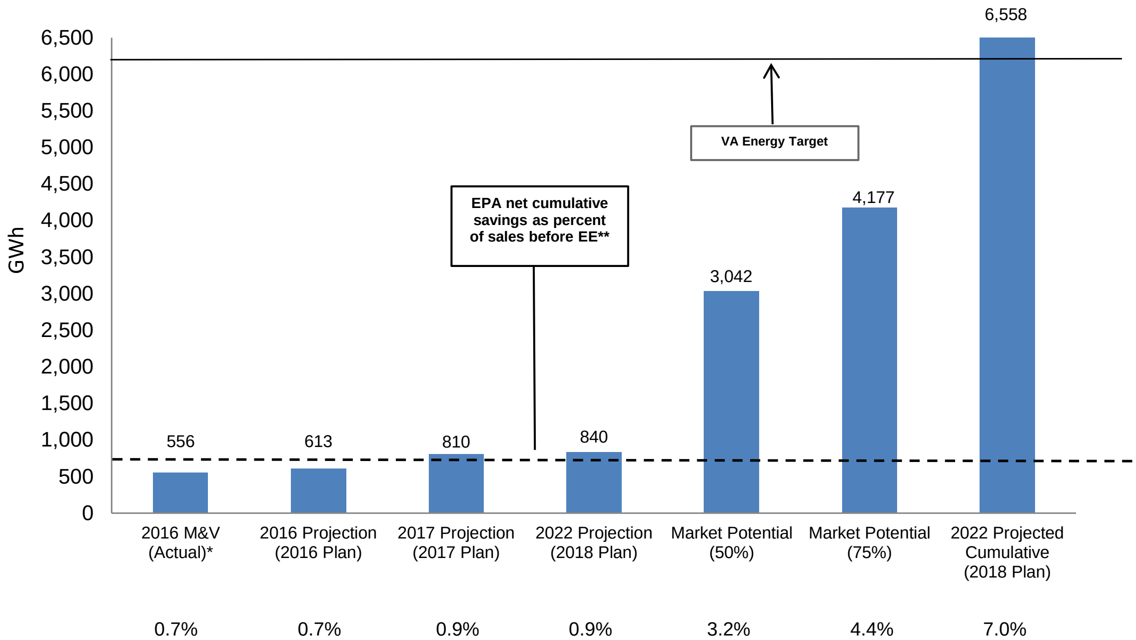


Figure 5.5.3 shows a comparison of the actual energy reductions for 2016 compared to the projected energy reductions for 2016. The actual energy reductions were 91% of the projected energy reductions for 2016. The energy reductions projected for 2022 in the 2017 Plan were 1,217 GWh. This level of energy reduction represents 40% of the amount shown in the 2017 DSM Potential Study (50% incentive level) for 2022.

Figure 5.5.3 – DSM Projections/Percent Sales



Note: *Actual energy savings are a function of SCC-approved program funding levels and measured energy savings/participation relative to program design projections.
**EPA Demand-Side Energy Efficiency Technical Support Document August 2015.
https://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents
"Data File: Demand-Side Energy Efficiency Appendix – Illustrative 7% Scenario.xlsx". Net Cumulative savings of 0.66% as percent of sales before EE.

A reasonable approach is to examine the projected energy reductions as a percent of energy sales. Those values are shown at the bottom of the graph for each of the energy reduction bars. Currently, the Company is producing actual energy reductions at a rate of about 0.7% of system energy sales. That is compared to a projected energy reduction of about 0.9% of sales in 2017. The projected energy reduction for the year 2022 is around 0.9% of sales. This level of energy reductions from DSM programs falls within a range of reasonable energy reductions. A reasonable range of energy reductions currently lies in a band of 0.5% to 1.0% of sales on an incremental basis.

In October 2017, the Company issued an RFI to solicit program concepts for a broad range of DSM programs. The information received in the RFI was used to develop an RFP for specific programs, which included a request for detailed design information. The RFP requested proposals for programs that may include measures identified in the 2017 DSM Potential Study, as well as other potential cost-effective measures based upon the current market trend. Responses from the RFP will be used to evaluate the feasibility and cost-effectiveness of proposed programs for customers in the Company's service territory.

In this 2018 Plan, there is a total reduction of 805 GWh by the end of the Planning Period in DSM related savings. By 2022, there are 840 GWh of reductions included in this 2018 Plan. There are several drivers that will affect the Company's ability to meet the current level of projected GWh reductions, including the cost-effectiveness of the DSM programs when filed, the SCC approval of newly filed programs, continuation of existing programs, the final outcome of proposed environmental regulations, and customers' willingness to participate in approved DSM programs.

5.5.1 STANDARD DSM TESTS

To evaluate DSM programs, the Company utilized four of the five standard tests from the California Standards Practice Manual. Based on SCC and NCUC findings and rulings in the Company's Virginia DSM proceedings[28] and North Carolina DSM proceedings,[29] the Company's future DSM programs are evaluated on both an individual and portfolio basis.

From the 2013 Plan going forward, the Company made changes to its DSM screening criteria in recognition of amendments to Va. Code § 56-576 enacted by the Virginia General Assembly in 2012 that a program "shall not be rejected based solely on the results of a single test." Therefore, the Company considers including DSM programs that have passing scores (cost/benefit scores above 1.0) on the Participant, Utility Cost, and Total Resource Cost ("TRC") tests.

In addition, during the 2017 planning cycle, the Company made a change in its DSM screening criteria based on the guidance in the Final Order in the 2016 DSM Proceeding where it denied the Phase VI Residential Home Energy Assessment Program. In this Order, the SCC states:

> [A]ccording to the Company's [Ratepayer Impact Measure ("RIM")] score of 0.39 for this program, the costs to non-participants far exceed the system-wide benefits. Furthermore, at a ratio of 1.22, the TRC Test for the Residential Home Energy Assessment Program, which measures the impact to the utility and program participants, does not significantly offset the low RIM score. Moreover, a comparison of the [NPV] of the tests does not alter our conclusion.[30]

The Company's analysis and evaluation during the 2018 Plan and 2017 DSM planning cycles were guided by this order.

Although the Company uses these criteria to assess DSM programs, there are circumstances that require the Company to deviate from the aforementioned criteria and evaluate certain programs that do not meet these criteria on an individual basis. These DSM programs serve important policy and public interest goals, such as those recognized in approving the Company's Low Income Program[31] and, more recently, the Company's Income & Age Qualifying Home Improvement Program.[32]

5.5.2 REJECTED DSM PROGRAMS

The Company did not reject any programs as part of the 2018 IRP process. A list of DSM rejected programs from prior IRP cycles is shown in Figure 5.5.2.1. Rejected programs may be re-evaluated and included in future DSM portfolios.

[28] Case Nos. PUE-2009-00023, PUE-2009-00081, PUE-2010-00084, PUE-2011-00093, PUE-2012-00100, PUE-2013-00072, PUE-2014-00071, PUE-2015-00089, and PUE-2016-00111.

[29] Docket No. E-22, Subs 463, 465, 466, 467, 468, 469, 495, 496, 497, 498, 499, 500, 507, 508, 509, 523, 524, 536, 538, and 539.

[30] *Petition of Virginia Electric and Power Company, For approval to implement new, and to extend existing, demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUE-2016-00111, Final Order at 11 (Jun. 1, 2017).

[31] Approved by the SCC in Case No. PUE-2009-00081, and by the NCUC in Docket No. E-22, Sub 463.

[32] Approved by the SCC in Case No. PUE-2014-00071 and the proposed extension in Case No. PUR-2017-00129, and by the NCUC in Docket No. E-22, Sub 523).

Figure 5.5.2.1 – Prior IRP Cycle Rejected DSM Programs

Program
Non-Residential HVAC Tune-Up Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
Residential Refrigerator Turn-In Program
Residential Solar Water Heating Program
Residential Water Heater Cycling Program
Residential Comprehensive Energy Audit Program
Residential Radiant Barrier Program
Residential Lighting (Phase II) Program
Non-Residential Refrigeration Program
Cool Roof Program
Non-Residential Data Centers Program
Non-Residential Curtailable Service
Non-Residential Custom Incentive
Enhanced Air Conditioner Direct Load Control Program
Residential Programmable Thermostat Program
Residential Controllable Thermostat Program
Residential Retail LED Lighting Program (VA)
Residential New Homes Program
Voltage Conservation
Residential Home Energy Assessment

5.5.3 NEW CONSUMER EDUCATION PROGRAMS

Future promotion of DSM programs will be through methods that raise program awareness as currently conducted in Virginia and North Carolina as discussed in Section 3.2.4.

5.5.4 ASSESSMENT OF OVERALL DEMAND-SIDE OPTIONS

Figure 5.5.4.1 represents approximately 805 GWh in energy savings from DSM programs at a system-level by 2033.

Figure 5.5.4.1 - DSM Energy Reductions

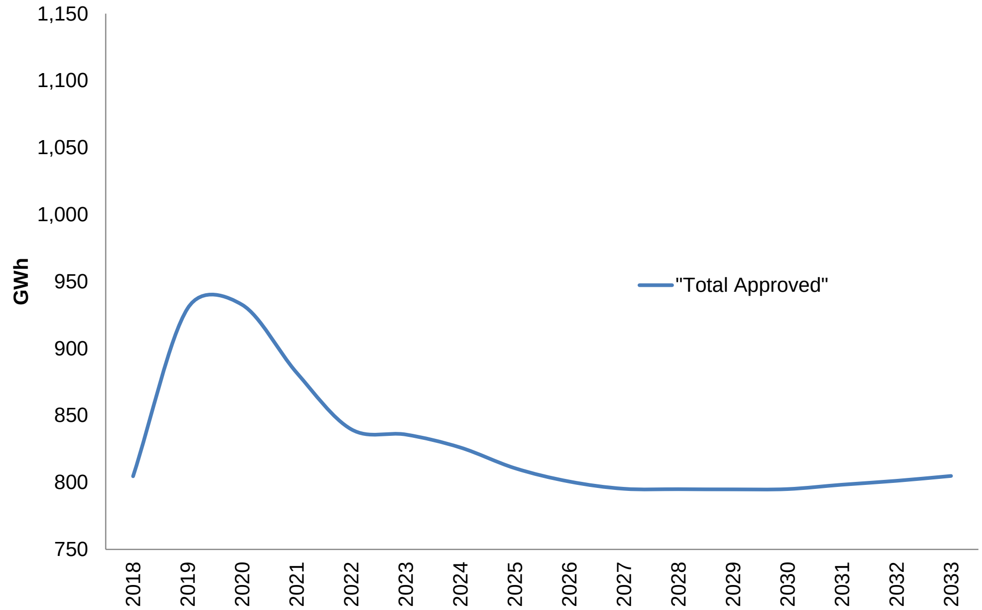
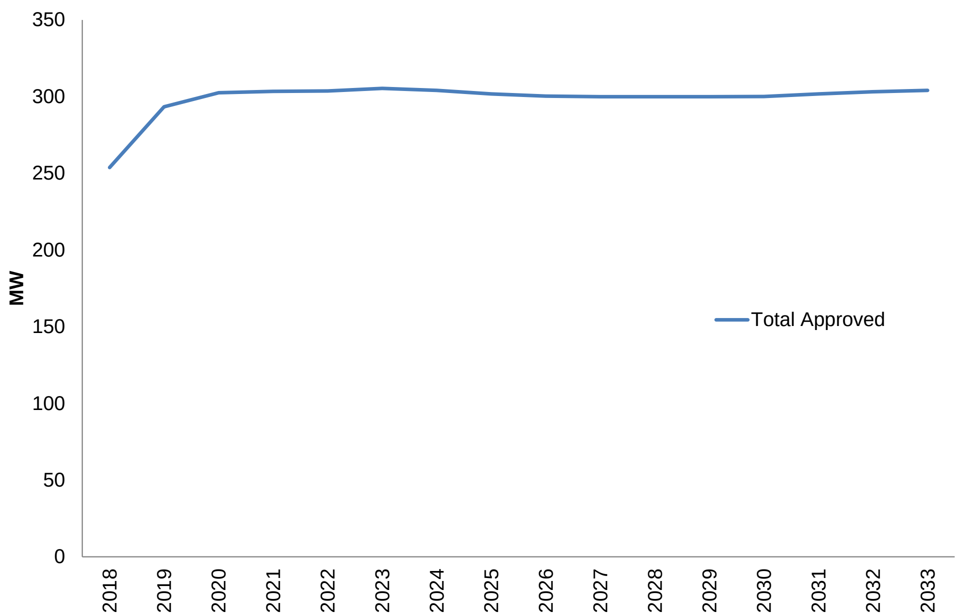


Figure 5.5.4.2 represents a system coincidental demand reduction of approximately 304 MW by 2033 from the DSM programs at a system-level.

Figure 5.5.4.2 - DSM Demand Reductions



The capacity reductions for the portfolio of DSM programs in this 2018 Plan are lower than the projections in the 2017 Plan. The total capacity reduction by the end of the Planning Period was 426 MW for the portfolio of DSM programs in the 2017 Plan and is 304 MW in this 2018 Plan. This represents approximately a 29% decrease in demand reductions.

The energy reduction for the DSM programs by the end of the Planning Period was 1,221 GWh in the 2017 Plan and is approximately 805 GWh in this 2018 Plan. This represents a 34% decrease in energy reductions. The majority of the differences between the 2017 Plan and the 2018 Plan is attributable to the outcome of the 2016 DSM proceeding in Case No. PUE-2016-00111. In that case, the SCC denied the Residential Home Energy Assessment Program and the extension of the DSM Phase II Residential Heat Pump Upgrade Program. In addition, during the course of the proceeding in response to concerns of SCC Staff regarding the Phase IV Non-Residential Prescriptive program, there was a change in the program spend and size, that resulted in reduced average kWh savings. Also, the SCC Staff questioned the inclusion of a refrigeration measure in the DSM Phase V Small Business Improvement Program. The removal of this measure is reflected in current projections in this 2018 Plan.

DSM Levelized Cost Comparison

The Company is providing a comparison of the cost of the Company's expected demand-side management costs relative to its expected supply-side costs. The costs are provided on a levelized cost per MWh basis for both supply- and demand-side options. The supply-side options' levelized costs are developed by determining the revenue requirements, which consist of the dispatch cost of each of the units and the revenue requirement associated with the capital cost recovery of the resource. The demand-side options' levelized cost is developed from the cost/benefit runs. The costs include the yearly program cash flow streams that incorporate program costs, customer incentives, and EM&V costs. The NPV of the cash flow stream is then levelized over the Planning Period using the Company's weighted average cost of capital. The costs for both types of resources are then sorted from lowest cost to highest cost and are shown in Figure 5.5.4.3.

Figure 5.5.4.3 – Comparison of per MWh Costs of Selected Generation Resources

Comparison of per MWh Costs of Selected Generation Resources to Phase II through Phase VI Programs	
Utility Cost Perspective	**Cost ($/MWh)**
Non-Residential Heating and Cooling Efficiency Program	$5.47
Residential Retail LED Lighting Program (NC Only)	$14.70
Non-Residential Lighting Systems and Controls Program	$14.72
Non-Residential Window Film Program	$19.79
Non-Residential Prescriptive Program	$33.12
Solar	$56.38
Small Business Improvement Program	$56.51
2X1 CC	$67.72
1X1 CC	$78.44
Onshore Wind	$94.10
CT	$107.05
Offshore Wind	$130.60
Nuclear	$141.52
Aero CT	$171.54
Fuel Cell	$199.25
Biomass	$221.08
Income and Age Qualifying Home Improvement Program	$237.17
Solar & Aero CT	$248.73
SCPC w/ CCS	$309.93
IGCC w/ CCS	$444.91
CVOW	$779.71

Note: The Company does not use levelized costs to screen DSM programs. DSM programs also produce benefits in the form of avoided supply-side capacity and energy cost that should be netted against DSM program cost. The DSM cost/benefit tests discussed in Section 5.5.1 are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options, and is the method the Company uses to screen DSM programs.
Values shown for these units reflect the Cost of Service method.

5.5.5 LOAD DURATION CURVES

The Company has provided load duration curves for the years 2019, 2023, and 2033 in Figures 5.5.5.1, 5.5.5.2, and 5.5.5.3, respectively.

Figure 5.5.5.1 - Load Duration Curve 2019

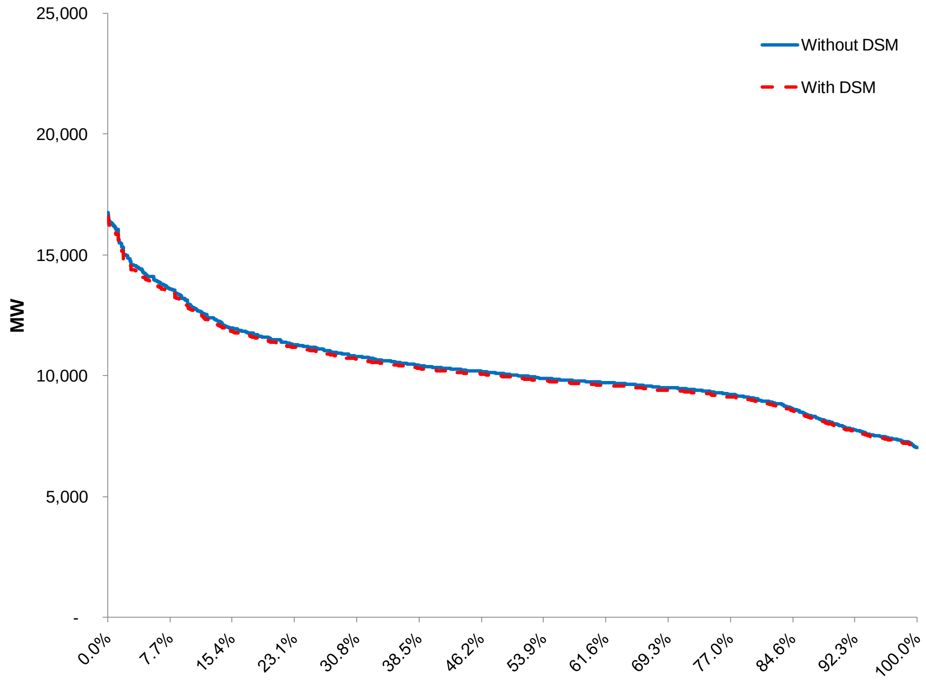


Figure 5.5.5.2 - Load Duration Curve 2023

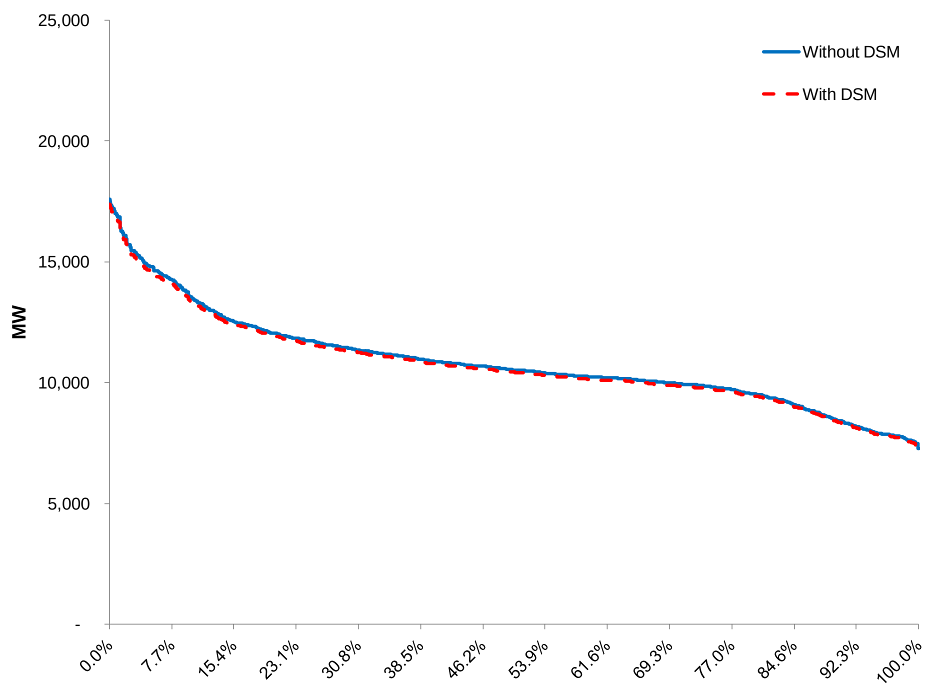
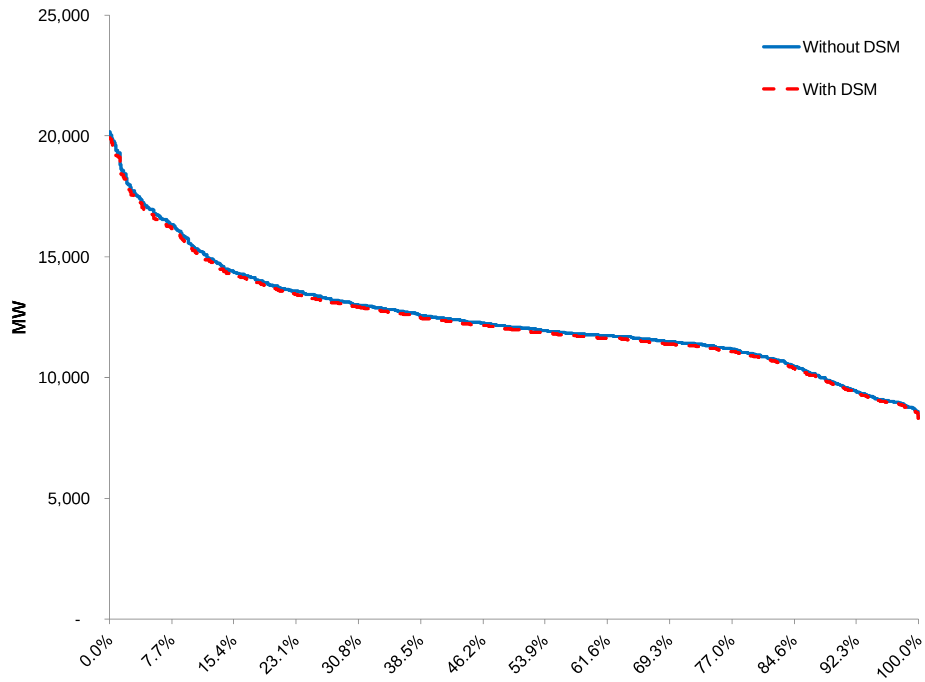


Figure 5.5.5.3 - Load Duration Curve 2033



5.6 FUTURE TRANSMISSION PROJECTS

Figure 7.4.1 provides a list of transmission lines that the Company plans to construct during the Planning Period.

CHAPTER 6 – DEVELOPMENT OF THE INTEGRATED RESOURCE PLAN

6.1 IRP PROCESS

The IRP process identifies, evaluates, and selects a variety of new resources to augment existing resources in order to meet customers' changing capacity and energy needs. The Company's approach to the IRP process relies on integrating supply-side resources, market purchases, cost-effective DSM programs, and transmission options over the Study Period. This integration is intended to produce a long-term plan consistent with the Company's commitment to provide reliable electric service at the lowest reasonable cost and to mitigate risk of unforeseen market events all while meeting regulatory and environmental requirements. This analysis develops a forward-looking representation of the Company's system within the larger electricity market that simulates the dispatch of its EGUs, market transactions, and DSM programs in an economic and reliable manner.

The IRP process begins with the development of a long-term annual peak and energy requirements forecast, as described in Chapter 2. Next, existing and approved supply- and demand-side resources, as described in Chapter 3, are compared with expected load and reserve requirements. This comparison yields the Company's expected future capacity and energy needs to maintain reliable service for its customers over the Study Period.

As described in Chapter 5, a feasibility screening, followed by a busbar screening curve analysis are conducted to identify supply-side resources, and a cost/benefit screening is conducted to determine demand-side resources that could potentially fit into the Company's resource mix. These potential resources and their associated economics are next incorporated into the Company's planning model, PLEXOS.

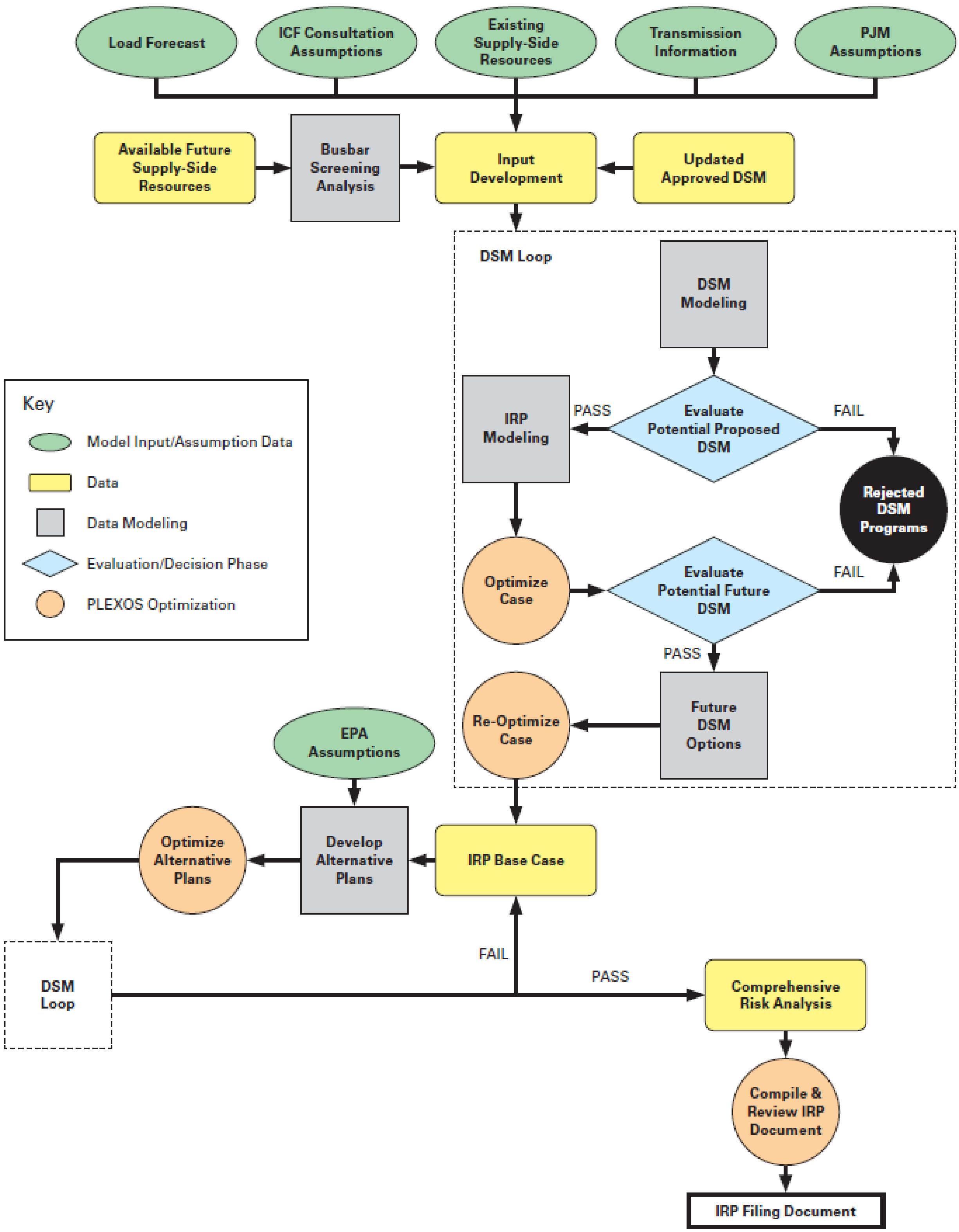
The next step is to develop a set of alternative plans using PLEXOS that represent plausible future paths forward considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against plausible scenarios that may occur given future market and regulatory uncertainty.

The Company has included in this 2018 Plan a comprehensive risk analysis in Section 6.7 that quantifies the operating cost risk and project development cost risk of each of the Alternative Plans. This analysis includes a broadband of variables used as forecasting assumptions in this 2018 Plan. These variables include fuel prices, effluent prices, market prices, renewable energy credit costs, construction costs, and the load forecast.

The results of both the cost analysis (PLEXOS modeling) and the comprehensive risk analysis are then compared in order to assess the best path forward to meet the future capacity and energy needs of the Company's customers.

The 2018 Plan development process is detailed in Figure 6.1.1

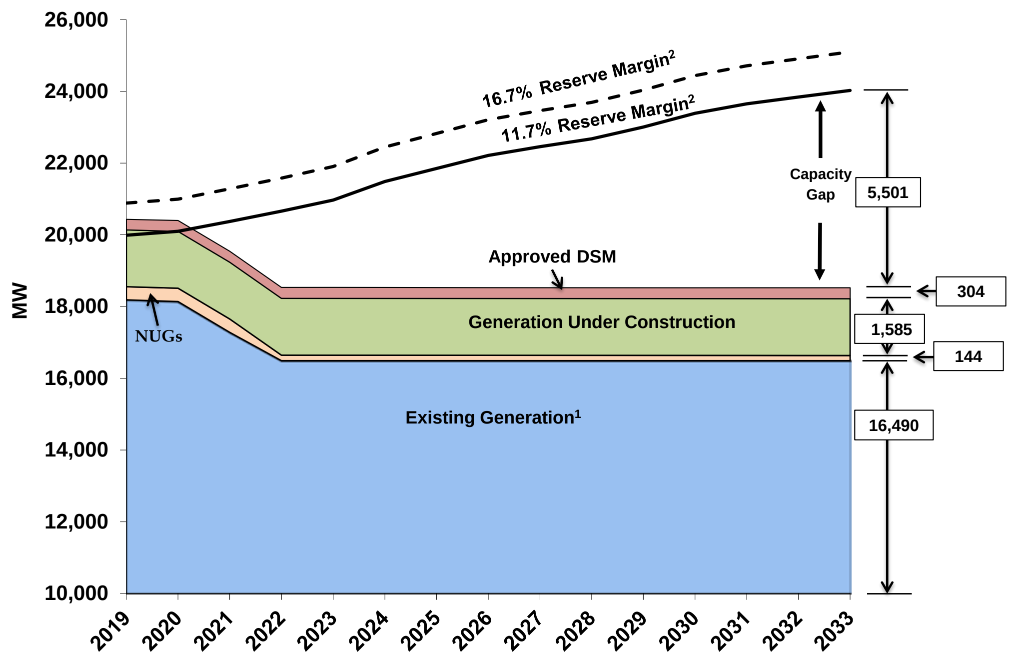
Figure 6.1.1 - Plan Development Process



6.2 CAPACITY & ENERGY NEEDS

As discussed in Chapter 2, over the Planning Period, the Company forecasted average annual growth rates of 1.4% in both peak and energy requirements for the DOM LSE. Chapter 3 presented the Company's existing supply- and demand-side resources, NUG contracts, generation retirements, and generation resources under construction. Figure 6.2.1 shows the Company's supply- and demand-side resources compared to the capacity requirement, including peak load and reserve margin. The area marked as "Capacity Gap" shows additional capacity resources that will be needed over the Planning Period in order to meet the capacity requirement. The Company plans to meet this capacity gap using a diverse combination of additional conventional and renewable generating capacity, DSM programs, and market purchases.

Figure 6.2.1 - Current Company Capacity Position (2019 – 2033)



Note: The values in the boxes represent total capacity in 2033.
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.

As indicated in Figure 6.2.1, the capacity gap at the end of the Planning Period is significant. The Planning Period capacity gap is expected to be approximately 5,501 MW. If this capacity deficit is not filled with additional resources, the reserve margin is expected to fall below the required 11.7% planning reserve margin (as shown in Figure 6.2.2) beginning in 2021 and continuing to decrease thereafter.

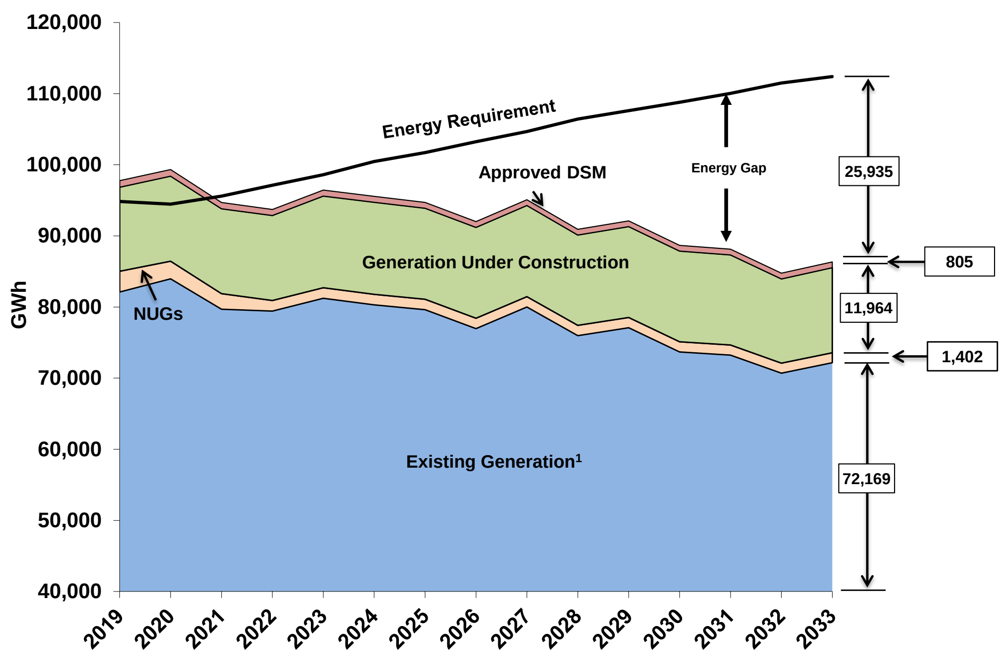
Figure 6.2.2 - Actual Reserve Margin without New Resources

Year	Reserve Margin (%)
2019	13.3%
2020	12.4%
2021	6.1%
2022	-0.8%
2023	-2.3%
2024	-4.7%
2025	-6.3%
2026	-7.8%
2027	-8.8%
2028	-9.7%
2029	-11.0%
2030	-12.5%
2031	-13.4%
2032	-14.1%
2033	-14.8%

The Company's PJM membership has given it access to a wide pool of generating resources for energy and capacity. However, it is critical that adequate reserves are maintained not just in PJM as a whole, but specifically in the DOM Zone to ensure that the Company's load can be served reliably and cost-effectively. Maintaining adequate reserves within the DOM Zone lowers congestion costs, ensures a higher level of reliability, and keeps capacity prices low within the region.

Figure 6.2.3 illustrates the amount of annual energy required by the Company after the dispatch of its existing resources. The Company's energy requirements increase significantly over time.

Figure 6.2.3 - Current Company Energy Position (2019 – 2033)



Note: The values in the boxes represent total energy in 2033.

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

The Company's long-term energy and capacity requirements shown in this section are met through an optimal mix of new conventional and renewable generation, DSM programs, and market resources that are derived using the IRP process.

6.3 MODELING PROCESSES & TECHNIQUES

The Company used a methodology that compares the costs of the Alternative Plans to evaluate the type and timing of resources that were included in those plans. The first step in the process was to construct a representation of the Company's current resource base. Then, future assumptions were used as inputs to PLEXOS including but not limited to load, fuel prices, emissions costs, maintenance costs, and resource costs. This analysis provided a set of future supply-side resources potentially available to the Company, along with their individual characteristics. A 3x1 CC was excluded from modeling in the 2018 Plan to prevent future grid stability issues due to the addition of too many large generators in the DOM Zone as well as limited gas availability. The types of supply-side resources that are available to the PLEXOS model are shown in Figure 6.3.1.

Figure 6.3.1 - Supply-Side Resources Available in PLEXOS

Dispatchable
Aero-derivative CT
Biomass
CC 1x1
CC 2x1
Coal w/CCS
CT
Fuel Cell
IGCC w/CCS
Nuclear (NA3)
Non Dispatchable
CVOW
Offshore Wind
Onshore Wind
Solar NUG
Solar PV
Solar Tag

Key: CC: Combined-Cycle; CT: Combustion Turbine (2 units); IGCC CCS: Integrated-Gasification Combined-Cycle with Carbon Capture and Sequestration; Coal CCS: Coal with Carbon Capture and Sequestration; CVOW: Coastal Virginia Offshore Wind; Solar PV: Solar Photovoltaic; Solar Tag: Solar PV unit at a brownfield site.

PLEXOS does not have the ability to conduct cost/benefit evaluations for DSM within the model itself, leading to the need for an additional model, tool, or process. For this reason, the Company has continued its use of Strategist for DSM evaluations using consistent data between the models. The inputs into Strategist are consistent with those in PLEXOS for the 2018 Plan. Supply-side options, market purchases, and currently approved demand-side resource options were optimized to arrive at the Alternative Plans presented in this 2018 Plan.

PLEXOS develops optimized resource plans based on the total NPV utility costs over the Study Period while simultaneously adhering to other market drivers, such as price forecasts derived from possible carbon regulations modeled in Plans B, C, D, and E. The NPV utility costs include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

6.4 ALTERNATIVE PLANS

The Company's analysis of the Alternative Plans is intended to represent plausible paths for future resource additions. Each of the Alternative Plans was optimized using least-cost analytical techniques given the constraints associated with that alternative to meet the differing compliance approaches.

Consistent with past Plans, the Company presents five Alternative Plans that represent plausible future paths for meeting the future electric needs of its customers.[33] This 2018 Plan assesses the portfolio expansions necessary to meet compliance with the Virginia RGGI Program (with unlimited imports), with RGGI (with unlimited and with limited imports), and with a potential Federal CO_2 Program consistent with ICF's forecast. As has become custom, the Company has also included an Alternative Plan that estimates future generation expansion in a world where there are no limits on CO_2 emissions.

The Alternative Plans also include the 12 MW (nameplate) CVOW as early as 2021; 760 MW (nameplate) of Virginia and North Carolina solar generation from NUGs, which are currently and expected to be under long-term contracts with the Company by 2020; and the 1,585 MW Greensville County Power Station, which is currently under construction and planned to enter commercial operation by 2019. Lastly, the Alternative Plans include Virginia Company-owned utility-scale solar generation: US-3 Solar 1, 142 MW (nameplate), and US-3 Solar 2, 98 MW (nameplate).

Additionally, the Alternative Plans acknowledge that 10 generating units are being placed into cold reserve in 2018. Bellemeade Power Station, Bremo Power Station Units 3 and 4, and Mecklenburg Power Station Units 1 and 2 were placed into cold reserve in April 2018. Pittsylvania Power Station will be placed into cold reserve in August 2018. Chesterfield Power Station Units 3 and 4 and Possum Point Power Station Units 3 and 4 will be placed into cold reserve in December 2018. "Cold reserve" does not mean permanent retirement. These units are currently planned to remain in cold reserve until 2021. These units, which total 1,292 MW of generation, can be reactivated in approximately six months if system needs and market conditions dictate. The Company will continue to maintain all required environmental permits for the units and continue to pay property taxes to the localities.

The Alternative 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 2032 and 2033, respectively, and the license extensions for North Anna Units 1 and 2 in 2038 and 2040, respectively.

Figure 6.4.1 reflects the Alternative Plans in tabular format.

[33] As previously discussed, the Company does not consider the CPP a plausible future path. Nevertheless, based on a broad interpretation of the 2017 Plan Final Order, the Company presents a CPP scenario in Appendix 1B.

Figure 6.4.1 – Alternative Plans

Year	Plan A: No CO_2 Tax	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
Approved DSM: 304 MW, 805 GWh by 2033					
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1)	Greensville SLR NUG(1)
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT AERO CT SLR (480 MW) CH5-6	CT AERO CT SLR (480 MW) CH5-6	CT AERO CT SLR (480 MW) CH5-6	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (400 MW)
2025	CT SLR (400 MW)	CT AERO CT SLR (400 MW) CL1-2	CT AERO CT SLR (400 MW) CL1-2	2X1 CC SLR (400 MW) CL1-2	CT SLR (480 MW)
2026	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)
2027	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)
2028	SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)
2029		CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (400 MW)
2030	CT	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (320 MW)
2031	CT SLR (160 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (480 MW)	CT SLR (80 MW)
2032	CT SLR (240 MW)	CT SLR (480 MW)	CT SLR (480 MW)	SLR (480 MW)	SLR (480 MW)
2033	SLR (80 MW)	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CC: Combined-Cycle; CH: Chesterfield Power Station; CL: Clover Power Station; CT: Combustion Turbine (2 units); CT AERO: Aero-derivative CT (119 MW); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.
2) These units entered into cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These units are planned to enter cold reserve in December 2018.

Additional resources and retirements are included in the Alternative Plans below:

Plan A: No CO_2 Tax
Plan A is based on the No CO_2 Tax scenario and is developed using least cost modeling methodology. Specifically, it selects:

- 4,122 MW of CT capacity; and
- 4,480 MW (nameplate) of solar.

Plan B: Virginia RGGI (unlimited imports)
Plan B was designed assuming that the Virginia RGGI Program is finalized as proposed. Specifically, Plan B assumes a partial return of allowance proceeds to generators within Virginia. Plan B assumes that the Company's compliance with RGGI under the Virginia RGGI Program is largely met through the use of imported energy and capacity. Plan B selects:

- 5,038 MW of CT capacity;
- 238 MW of CT Aero capacity;
- 6,400 MW (nameplate) of solar; and
- The retirement of Chesterfield Units 5 and 6 in 2023, and Clover Units 1 and 2 in 2025.

Plan C: RGGI (unlimited imports)
Plan C assumes that Virginia is a full member of RGGI. Specifically, Plan C assumes full auction of RGGI allowances with no return of allowance proceeds to generators within Virginia. Plan C is intended as a comparison against Plan B, and reflects the incremental cost of purchasing all allowances with no offsetting compensation payment. Specifically, Plan C selects:

- 5,038 MW of CT capacity;
- 238 MW of CT Aero capacity;
- 6,400 MW (nameplate) of solar; and
- The retirement of Chesterfield Units 5 and 6 in 2023, and Clover Units 1 and 2 in 2025.

Plan D: RGGI (limited imports)
Plan D assumes that Virginia is a full member of RGGI. Plan D assumes that the Company's compliance with RGGI is met through generation build within Virginia with limited import power. Specifically, Plan D selects:

- 4,122 MW of CT capacity;
- 119 MW of CT Aero capacity;
- 6,400 MW (nameplate) of solar; and
- The retirement of Chesterfield Units 5 and 6 in 2023, and Clover Units 1 and 2 in 2025.

Plan D also includes 1,062 MW of 2x1 CC capacity;

Plan E: Federal CO_2 Program
Plan E anticipates that Virginia does not join RGGI (either directly or through the Virginia RGGI Program) and that federal CO_2 legislation is enacted beginning in 2026. Specifically, Plan E selects:

- 3,664 of CT capacity; and
- 5,760 MW (nameplate) of solar.

Figure 6.4.2 illustrates the renewable resources included in the Alternative Plans over the Study Period (2019 to 2043).

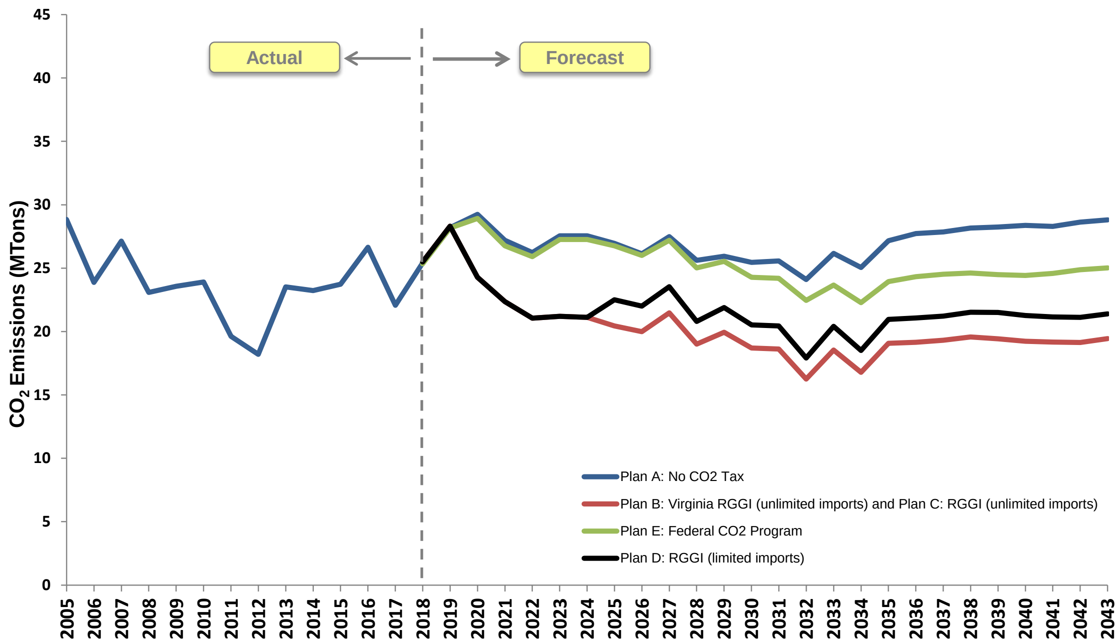
Figure 6.4.2 – Renewable Resources in the Alternative Plans through the Study Period

	Nameplate MW	Plan A: No CO_2 Tax	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
Existing Resources[1]	533	x	x	x	x	x
VCHEC Biomass	61	x	x	x	x	x
Solar NUGs[2]	760	x	x	x	x	x
CVOW	12	x	x	x	x	x
US-3 Solar 1	142	x	x	x	x	x
US-3 Solar 2	98	x	x	x	x	x
Solar PV	Varies	4,960	6,960	6,960	6,960	6,960

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2020.

Figure 6.4.3 shows the total tons of CO_2 emitted for all generation resources including CTs, contracted NUGs, and purchases in each of the Alternative Plans through the Study Period.

Figure 6.4.3 – Virginia CO_2 Output from Dominion Energy Virginia units for the Alternative Plans



Note: Plan B: Virginia RGGI (unlimited imports) and Plan C: RGGI (unlimited imports) have the same build plan and the same amount of CO_2 emissions. The difference between Plans B and C is cost, as shown in Section 6.5.

6.5 ALTERNATIVE PLANS NPV COMPARISON

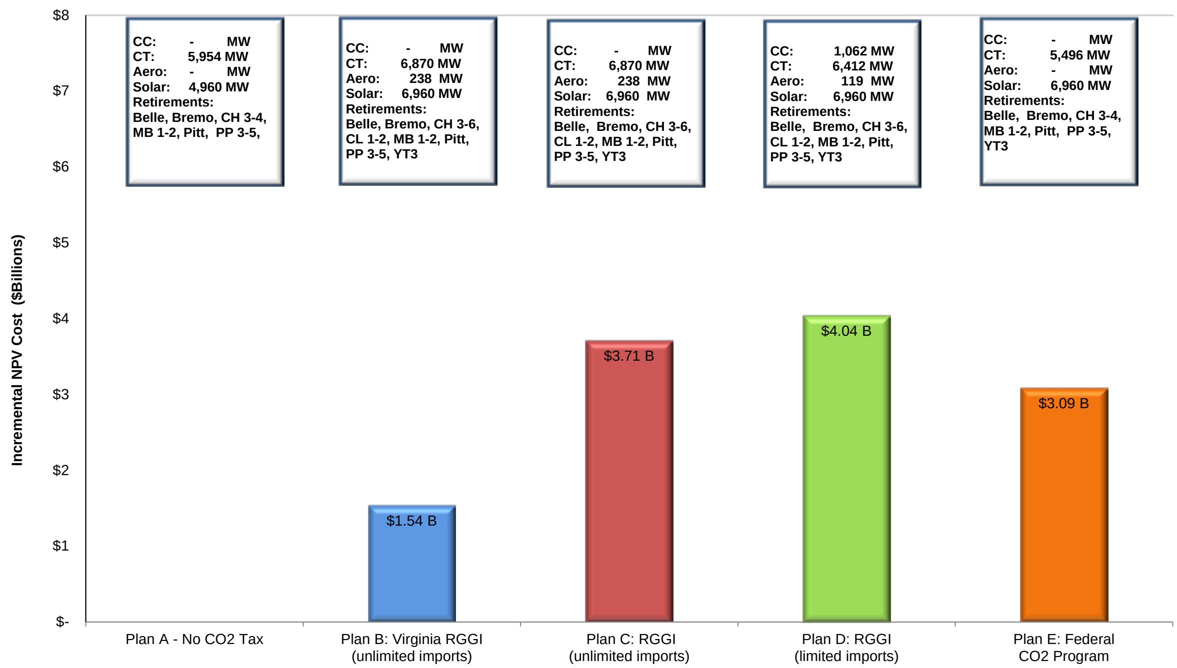
The Company evaluated the Alternative Plans using base-case assumptions to compare and contrast the NPV utility costs over the Study Period. Figure 6.5.1 illustrates the NPV compliance cost for the Alternative Plans by showing the additional expenditures by the Alternative Plans over Plan A for the Study Period.

Figure 6.5.1 – NPV Compliance Cost of the Alternative Plans over Plan A

	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
NPV Compliance Cost ($B)	$ 1.54	$ 3.71	$ 4.04	$ 3.09

Figure 6.5.2 illustrates the incremental NPV compliance cost for the Alternative Plans over Plan A for the Study Period.

Figure 6.5.2 – Incremental NPV Compliance Cost of the Alternative Plans over Plan A (2019 – 2043)



Note: The MWs in this figure do not include CVOW, DSM, Greensville, and US-3 Solar Units 1 and 2.

6.6 RATE IMPACT ANALYSIS

Va. Code § 56-599 B 9 requires the Company to evaluate "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations." Accordingly, the Company evaluated the residential rate impact of each Alternative Plan against Plan A. [34] The results of this analysis are shown in Figures 6.6.1 through 6.6.6, which reflect the nominal dollar impact and percentage increase for a typical residential customer, using 1,000 kWh per month, each year starting in 2020 through 2043. In Plans B, C, and D, the increase in rates in 2023 and 2025 are attributable to the cost write-offs for unit retirements.

In Plan E: Federal CO_2 Program, the decrease in rates in years 2020 through 2026 reflects lower fuel prices in the near-term due to fewer nuclear retirements, more renewable additions, and more coal retirements over the long-term when compared to the Plan A: No CO_2 Tax. The lower fuel prices lead to lower power prices in the near-term.

[34] The Company includes a rate impact analysis of a CPP scenario in Appendix 1B.

Figure 6.6.1 – Monthly Rate Increase of Alternative Plans vs. Plan A

	Increase Compared to Plan A: No CO_2 Tax ($)			
Year	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
2020	0.60	2.17	2.19	(0.24)
2021	0.83	2.34	2.47	(0.34)
2022	1.01	2.54	3.03	(0.30)
2023	10.89	12.49	13.40	(0.34)
2024	2.22	3.86	4.98	(0.30)
2025	6.91	8.55	10.05	(0.28)
2026	3.00	4.66	6.02	(0.02)
2027	3.36	5.21	6.48	0.52
2028	3.87	5.56	6.83	1.76
2029	4.39	6.24	7.29	2.35
2030	4.54	6.34	7.35	2.82
2031	4.73	6.59	7.41	3.53
2032	4.99	6.67	7.40	4.80
2033	4.83	6.84	7.52	5.62
2034	4.77	6.66	7.26	6.66
2035	4.69	6.92	7.37	7.87
2036	4.63	6.95	7.27	8.65
2037	4.39	6.82	7.35	9.21
2038	4.25	6.81	7.42	9.97
2039	4.24	6.88	7.40	10.79
2040	3.95	6.67	6.99	11.68
2041	3.84	6.65	6.90	12.75
2042	3.87	6.77	6.95	14.05
2043	3.60	6.57	6.66	15.46

Figure 6.6.2 – Monthly Rate Increase of Alternative Plans vs. Plan A

	Increase Compared to Plan A: No CO_2 Tax (%)			
Year	Plan B: Virginia RGGI (unlimited imports)	Plan C: RGGI (unlimited imports)	Plan D: RGGI (limited imports)	Plan E: Federal CO_2 Program
2020	0.5%	1.9%	1.9%	-0.2%
2021	0.7%	2.0%	2.1%	-0.3%
2022	0.8%	2.1%	2.5%	-0.2%
2023	9.1%	10.4%	11.2%	-0.3%
2024	1.8%	3.2%	4.1%	-0.2%
2025	5.6%	6.9%	8.1%	-0.2%
2026	2.4%	3.7%	4.8%	0.0%
2027	2.6%	4.1%	5.1%	0.4%
2028	3.0%	4.3%	5.3%	1.4%
2029	3.4%	4.8%	5.7%	1.8%
2030	3.5%	4.9%	5.6%	2.2%
2031	3.6%	5.0%	5.6%	2.7%
2032	3.7%	5.0%	5.5%	3.6%
2033	3.5%	5.0%	5.5%	4.1%
2034	3.5%	4.9%	5.3%	4.9%
2035	3.4%	5.1%	5.4%	5.8%
2036	3.4%	5.1%	5.3%	6.3%
2037	3.2%	5.0%	5.4%	6.7%
2038	3.1%	4.9%	5.4%	7.2%
2039	3.1%	5.0%	5.3%	7.8%
2040	2.8%	4.8%	5.0%	8.4%
2041	2.8%	4.8%	4.9%	9.1%
2042	2.8%	4.8%	5.0%	10.0%
2043	2.6%	4.6%	4.7%	10.9%

Figure 6.6.3 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A

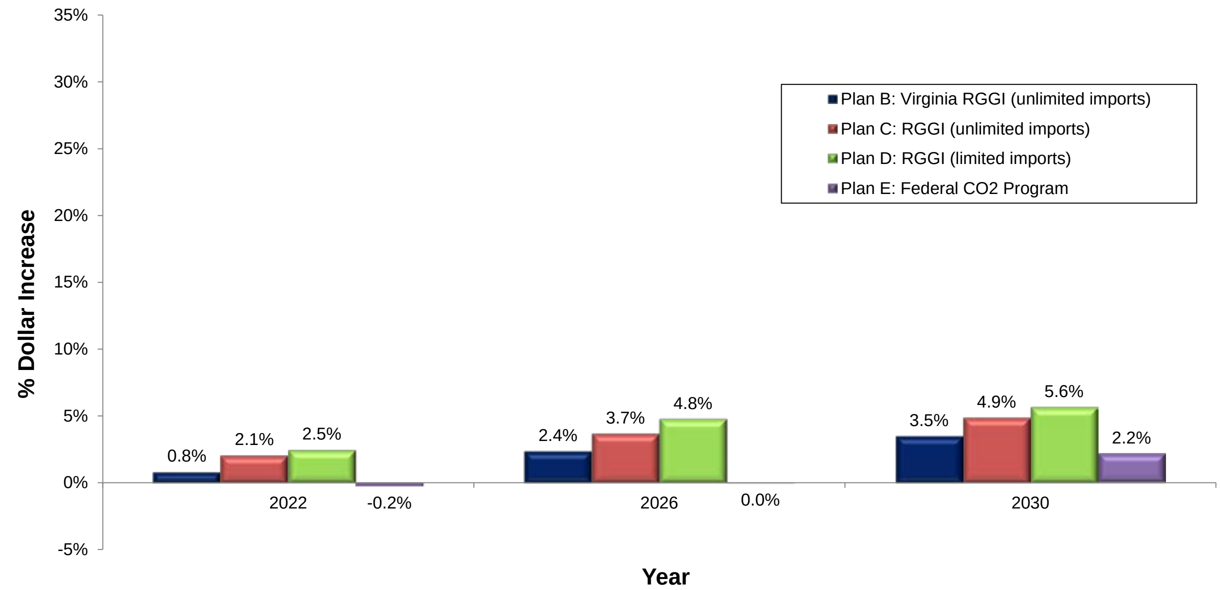


Figure 6.6.4 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A

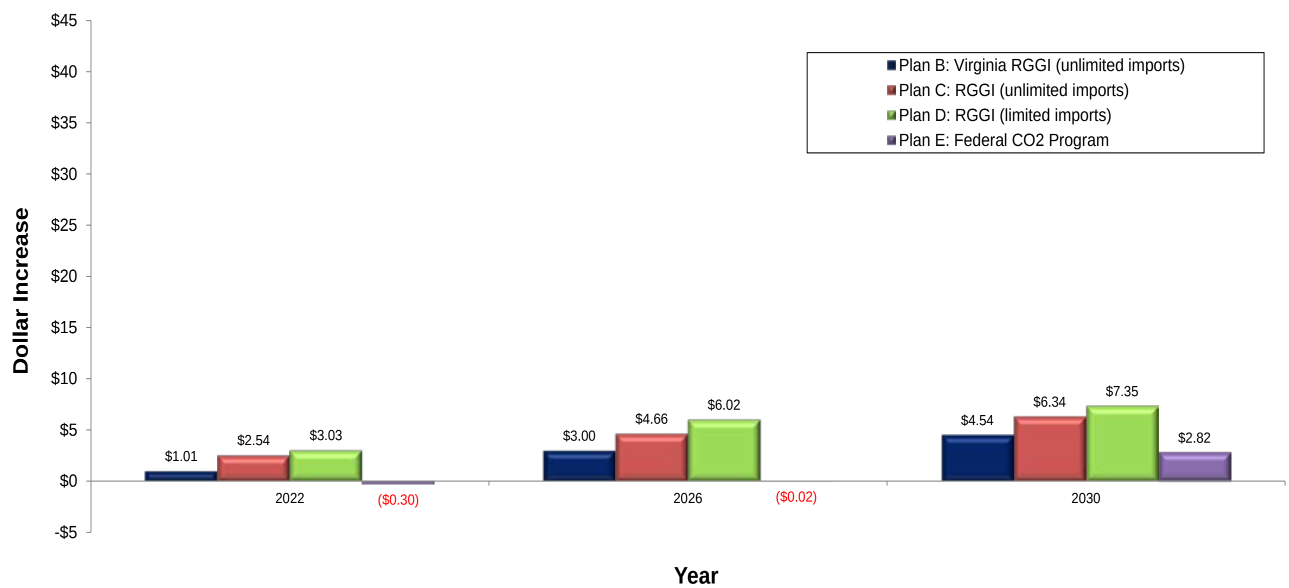


Figure 6.6.5 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A

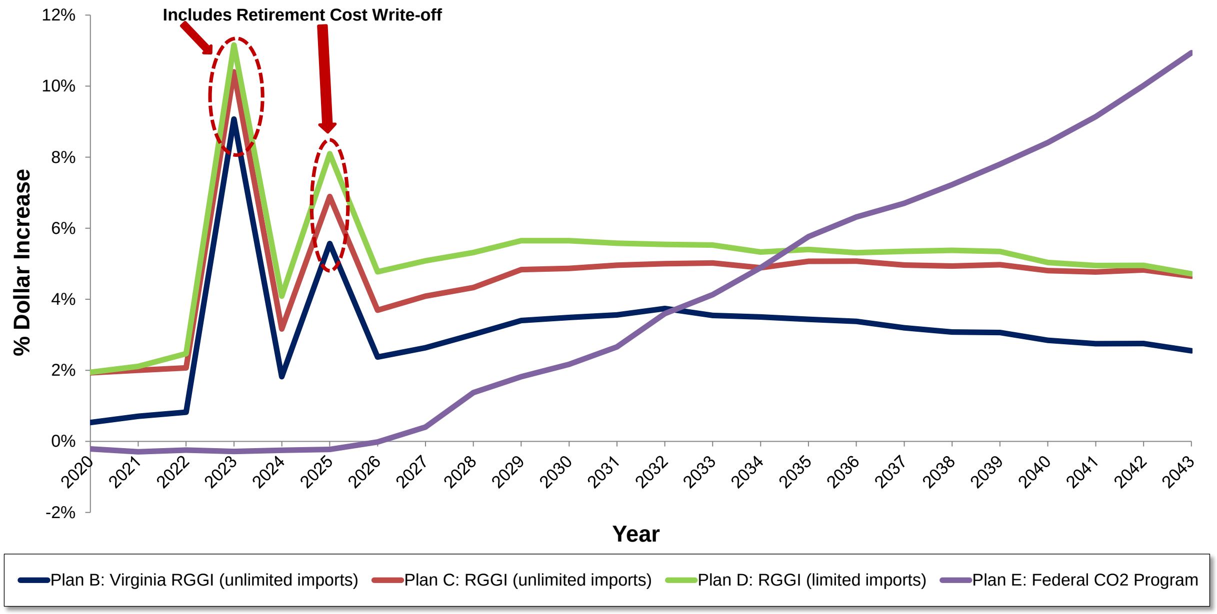
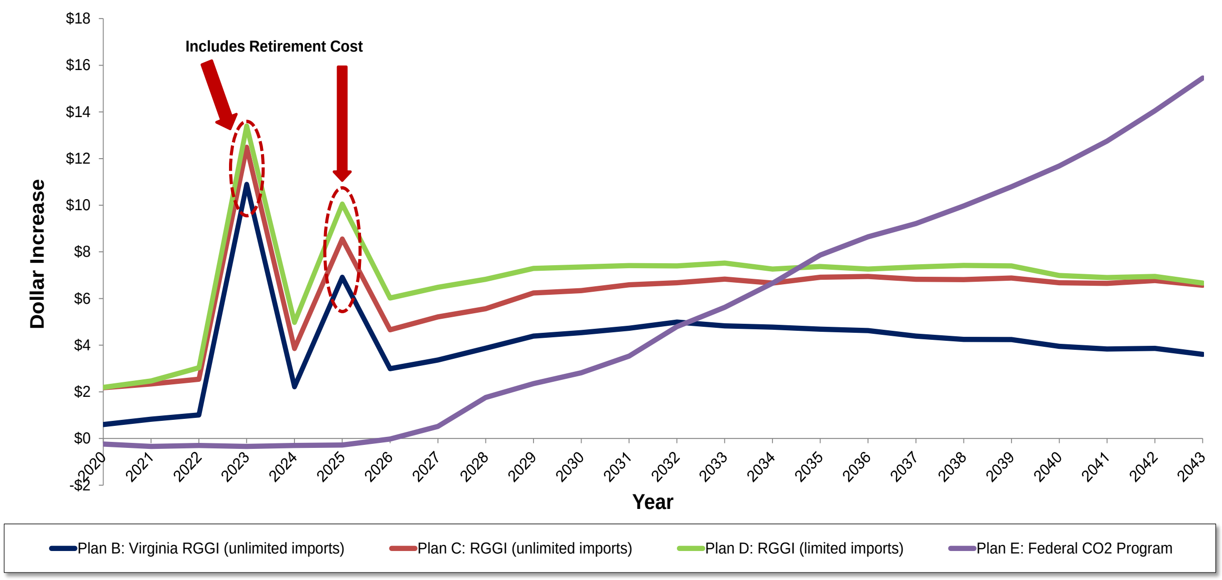


Figure 6.6.6 – Residential Monthly Bill Increase for Alternative Plans compared to Plan A



6.7 COMPREHENSIVE RISK ANALYSIS

6.7.1 OVERVIEW

To evaluate the risks associated with the Alternative Plans presented in Section 6.4, this 2018 Plan includes a comprehensive risk analysis methodology. Similar to the 2017 Plan, the Company utilized the same stochastic (probabilistic) methodology and supporting software developed by Pace Global (a Siemens business) in concert with the AURORA multi-area production costing model (licensed from EPIS, Inc.). Using this analytic and modeling framework (hereinafter referred to as the "Pace Global Methodology"), the Alternative Plans, each treated as a fixed portfolio of existing and expansion resources plus DSM measures, were evaluated and compared on the dimensions of average total production cost relative to two measures of cost-related risk: (i) standard deviation cost and (ii) semi-standard deviation cost.

The Pace Global Methodology is an adaptation of modern portfolio theory, which attempts to quantify the trade-off that usually exists between portfolio cost and portfolio risk, a quantification that is not addressed in the traditional least-cost planning paradigm. Measuring the risk associated with proposed expansion plans quantifies, for example, whether adopting any one particular plan comes with greater cost and risk for customers when compared to the cost and risk for competing plans. In the same way, comparing plans with different capacity mixes—which have different cost and risk profiles—potentially reveals the value of generation mix diversity. Importantly, it is impractical to include all possible sources of risk in this assessment, so the assessment includes only the most significant drivers to plan cost and variability.

At a high level, the Pace Global Methodology is comprised of the following steps:

1. Identify and create a stochastic model for each key source of portfolio risk which in this analysis are:
    - Natural gas prices;
    - Natural gas basis;
    - Coal prices;
    - Oil prices (for proxy of coal transportation cost);
    - Load (electricity demand);
    - Hourly solar generation;
    - CO_2 emission allowance prices; and
    - New generation capital cost.

2. Generate a set of stochastic realizations for the key risk factors within the PJM region and over the Study Period using Monte-Carlo techniques. For purposes of this analysis, 200 stochastic realizations were produced for each of the key risk factors.
3. Subject each of the Alternative Plans separately to this same set of stochastic risk factor outcomes by performing 200 AURORA multi-area model production cost simulations, which cover a significant part of the EI, using the risk factor outcomes as inputs.
4. Use the AURORA simulation results to calculate the expected levelized all-in average cost and the associated risk measures for each of the Alternative Plans.

The following Alternative Plans were evaluated under the comprehensive risk analysis:

- Plan A: No CO_2 Tax
- Plan B: Virginia RGGI (unlimited imports)
- Plan C: RGGI (unlimited imports)
- Plan D: RGGI (limited imports)
- Plan E: Federal CO_2 Program

6.7.2 PORTFOLIO RISK ASSESSMENT

Upon completion of the AURORA simulations described in Section 6.7.1 post-processing of each Alternative Plan's annual average total (fixed plus variable) production costs proceeded in the following steps:

- Levelize the annual average total production costs for each of the 200 draws over the 25-year Study Period using a nominal discount rate of 6.31%.
- Statistically summarize the 200 levelized average total production costs values into:
    - **Expected value**: the arithmetic average value of the 200 draws.
    - **Standard deviation**: the square-root of the average of the squared differences between each draw's levelized value and the mean of all 200 levelized values. This is a standard measure of overall cost risk to the Company's customers.
    - **One way (upward) standard deviation (semi-standard deviation)**: the standard deviation of only those levelized average production costs which exceed the expected value (i.e., the mean of all 200 levelized values). This is a measure of adverse cost risk to the Company's customers.

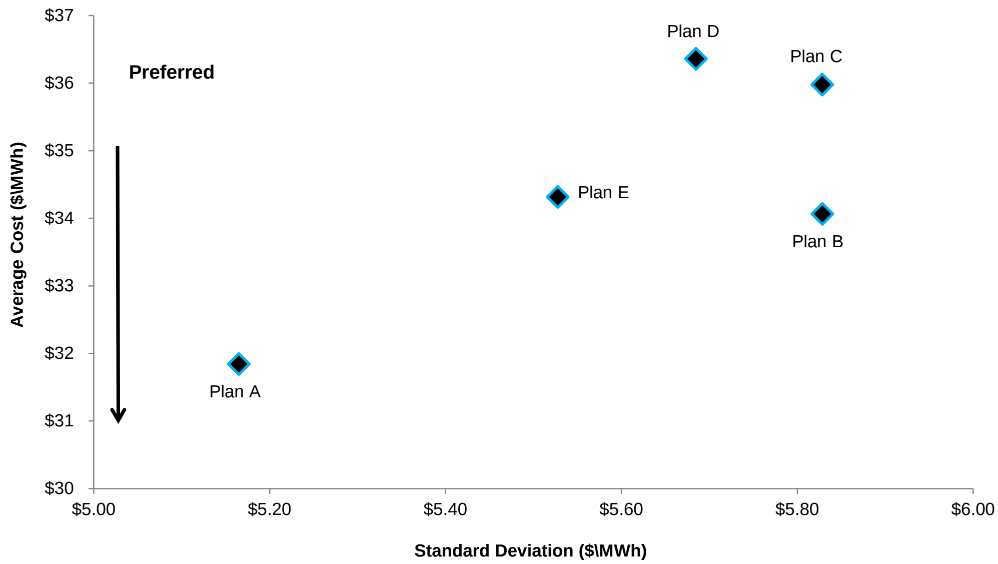
The resulting values are shown for the Alternative Plans in Figure 6.7.2.1 for comparative purposes. Plans with lower values for expected levelized average cost, standard deviation, and semi-standard deviation are more beneficial for customers.

Figure 6.7.2.1 - Alternative Plan Portfolio Risk Assessment Results

2018 $/MWh Plan	Expected Levelized Average Cost	Standard Deviation	Semi Standard Deviation
Plan A: No CO_2 Tax	$31.84	$5.16	$5.73
Plan B: Virginia RGGI (unlimited imports)	$34.06	$5.83	$6.36
Plan C: RGGI (unlimited imports)	$35.98	$5.83	$6.36
Plan D: RGGI (limited imports)	$36.36	$5.68	$6.17
Plan E: Federal CO_2 Program	$34.32	$5.53	$5.91

Plan A: No CO_2 Tax had the lowest levelized average cost and risk of all Alternative Plans. This result is expected given that Plan A was evaluated in a future that assumes no new CO_2 regulation in any state, including Virginia. Among all other Alternative Plans with different regulations on carbon emissions, Plan B: Virginia RGGI (unlimited imports) had the lowest expected cost and Plan E: Federal CO_2 Program had the lowest risk based on the standard deviation. A visual display of average cost against risk as measured by standard deviation for the Alternative Plans is shown in Figure 6.7.2.2.

Figure 6.7.2.2 – Alternative Plans Mean-Variance Plot



6.7.3 INCLUSION OF THE DISCOUNT RATE AS A CRITERION IN RISK ANALYSIS

The Company also included discount rate as a criterion in its risk analysis. As described in Section 6.4, each of the Alternative Plans was developed based on minimization of total NPV utility costs over the Study Period subject to constraints, such as the reserve margin target and different regulations on carbon emissions. The discount rate is a key parameter in the NPV calculation and plays an important role in computing the risk analysis results. The Company notes the following points to form a background for the discussion on the discount rate:

- In principle, the appropriate discount rate to evaluate alternative expansion plans is from the standpoint of utility customers collectively, not the utility. While the customer discount rate is unobservable, it is a function of the opportunity costs facing utility consumers. This rate would be the same regardless of the expansion plan being evaluated. Absent knowledge of the customer discount rate, it is not unreasonable to use the utility discount rate as a proxy.
- In developing the Alternative Plans and in the comprehensive risk analysis, the discount rate used is the Company's five-year forecasted nominal after-tax weighted average cost of capital ("WACC"). This same discount rate is applied regardless of the expansion options under consideration. In this way, NPV costs are calculated on a consistent basis across all Alternative Plans. Because risk simulation results are in nominal 2018 dollars, after-tax WACC is used to levelize the average production costs over the Study Period for each of 200 stochastic realizations.
- Capital revenue requirements projected for each generation expansion option include EPC costs, capitalized financing costs, and equity return incurred prior to commercial operation.
- The comprehensive risk analysis results include the effect of uncertainty in the levelized capital revenue requirements for each type of expansion option. The risk analysis assumed the greatest uncertainty was for new nuclear and offshore wind projects and the least uncertainty was for technologies for which there is a lower per project capital requirements and/or for which the Company has proven construction experience.

Inclusion of the discount rate as a risk criterion is advisable because expansion plans that include significantly large and risky future capital outlays could mean that investors would require higher returns in compensation for the larger amount of capital at risk. It may also imply potentially significant changes in the Company's future capital structure because the appropriate discount rate would be higher than that for Alternative Plans comprised of less capital intensive or risky projects. Therefore, using a higher discount rate for such Alternative Plans would have the incorrect and implausible result of yielding lower expected NPV costs.

An alternative approach is to apply a risk-adjusted discount rate to the Alternative Plans that include high capital costs or high risk projects. Determining the appropriate risk-adjustment to the discount rate is problematic and is not known by the Company. For the present purpose of including the discount rate as a criterion in the risk analysis, Figures 6.7.3.1 and 6.7.3.2 show the results before and after a zero discount rate is applied to Plan D: RGGI (limited imports), which has the highest NPV cost of the Alternative Plans, and Plan C: RGGI (unlimited imports), which has the highest standard deviation of the Alternative Plans. Using a zero discount rate attributes the maximum possible degree of risk adjustment to the discount rate for these two Alternative Plans and therefore provides an upper bound for such risk-adjusted discounting.

Figure 6.7.3.1 – Plan D: RGGI (limited imports) Risk Assessment Results

2018 Plan	Levelized	Standard	Semi Standard
$/MWh	Average Cost	Deviation	Deviation
Plan D: RGGI (limited imports) - not risk adjusted	$36.36	$5.68	$6.17
Plan D: RGGI (limited imports) - risk adjusted	$42.25	$7.76	$9.07

Figure 6.7.3.2 – Plan C: RGGI (unlimited imports) Risk Assessment Results

2018 Plan	Levelized	Standard	Semi Standard
$/MWh	Average Cost	Deviation	Deviation
Plan C: RGGI (unlimited imports) - not risk adjusted	$35.98	$5.83	$6.36
Plan C: RGGI (unlimited imports) - risk adjusted	$41.99	$7.98	$9.28

Based on these numbers, it is evident that on a risk-adjusted basis, Plan D: RGGI (limited imports) still has the largest expected average production cost, while Plan C: RGGI (unlimited imports) still has the largest risk measured by both standard deviation and semi-standard deviation among all Alternative Plans.

While the Company includes this discount rate analysis, none of the Alternative Plans in this 2018 Plan includes what the Company believes to be capital-intensive high-risk generation, such as new nuclear units.

6.7.4 IDENTIFICATION OF LEVELS OF NATURAL GAS GENERATION WITH EXCESSIVE COST RISKS

The SCC has directed the Company to specifically identify the levels of natural gas-fired generation where operating cost risks may become excessive or provide a detailed explanation as to why such a calculation cannot be made." In this 2018 Plan, each of the Alternative Plans was developed to comply on a standalone basis with different forms of carbon emission regulation. The results of the comprehensive risk analysis reflect the expected cost and estimated risk associated with each Alternative Plan in the context of a no carbon emission regulation or a particular mode of regulation. In developing each of the Alternative Plans, the criterion used was minimization (subject to constraints) of NPV costs without considering the associated level of risk. Alternative Plan risk levels were assessed only after it was determined to be the lowest cost from among all feasible candidate plans. Developing Alternative Plans that considered both cost and risk jointly as criteria would have required the following different process:

- The expansion planning process would have to determine the "efficient frontier" from among all feasible candidate plans. The efficient frontier identifies a range of feasible plans each with the lowest level of risk for its given level of expected cost. Identifying the efficient frontier is not practical using traditional utility planning software and computing resources. If the efficient frontier could be determined, then any candidate plan with risk levels higher than the efficient frontier could reasonably be characterized as having excess risk in the sense that there exists a plan on the efficient frontier with the same expected cost but with lower risk.
- The Company would need to know the "mean-variance utility function" (i.e., the risk aversion coefficient) of its customers collectively in order to select the feasible plan that optimally trades off cost and risk from among competing plans. This function could be applied regardless of whether it is possible to determine the efficient frontier. However, this function is <u>not</u> known, meaning that planners are unable to determine levels of plan risk that are unacceptable or that become excessive for customers.

In the absence of these risk evaluation tools, it is not technically possible to determine an absolute level of plan risk that becomes excessive, much less to determine that level of gas-fired generation within a plan that poses excessive cost risk for customers. Moreover, the absolute level of natural gas generation within a plan does not necessarily lead to greater risk; rather, all else being equal, it is the degree of overall supply diversity that drives production cost risk.

Because the notion of excessive risk is inherently relative, Company planners can apply a ranked preference approach through which a plan is preferred if its expected cost and measured risk are both less than the corresponding values of any competing plan. The ranked preference approach does not need to rely on a definition of excessive risk, but only on the principle that customers should prefer a plan that is simultaneously lowest in cost and in risk among competing plans. In the 2018 Plan, the results of the comprehensive risk analysis show that Plan A: No CO_2 Tax has the lowest expected cost and risk than any of the other Alternative Plans. However, Plan A does not assume any regulation on carbon emissions and may not be preferred on grounds unrelated to risk. But, comparing Plan B: Virginia RGGI (unlimited imports) with Plan E: Federal CO_2 Program shows that Plan E has somewhat lower risk than Plan B, but with a slightly higher expected cost. In this case, it is not clear which of the two Plans should be preferred. The planner could apply a mean-variance utility function (i.e., the customer risk aversion coefficient), if known, to ultimately determine which Alternative Plan is preferable. Without this coefficient, however, it can be reasonably assumed that Plan B would be preferable because it is lower cost with approximately the same level of risk.

6.7.5 OPERATING COST RISK ASSESSMENT

The Company analyzed ways to mitigate operating cost risk associated with natural gas-fired generation through the use of long-term supply contracts that lock in a stable price, long-term investment in gas reserves, long-term firm transportation, and on-site liquefied natural gas storage.

Supply Contract/Investment in Gas Reserves

For the purpose of analyzing long-term supply contracts and long-term investments in gas reserves, the Company utilized the stochastic analysis to determine the reduction in volatility that can be achieved by stabilizing prices on various volumes of natural gas. The expected price of natural gas as determined by the stochastic analysis is utilized to stabilize market price for this analysis. To analyze operating cost risk of such price stabilizing arrangements the price of natural gas is "fixed" at the expected value prices for a portion of the total fueling needs. The evaluation measures the reduction in plan risk by comparing the standard deviation between a plan with various quantities of "fixed" price natural gas and the same plan without "fixed" price natural gas. This methodology is representative of measuring the impact of a long-term supply contract and/or long-term investment in gas reserves on overall plan risk. In either case, the actions would simulate committing to the purchase of natural gas supply over a long term at prevailing market prices at the time of the transaction. The primary benefit of such a strategy is to stabilize fuel prices, not to ensure below-market prices. Figures 6.7.5.1 through 6.7.5.4 indicate the reduction in portfolio risk associated with various quantities of natural gas at fixed price contracts or a natural gas reserve investment.

Figure 6.7.5.1 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – No Natural Gas at Fixed Price

No Natural Gas at Fixed Price			
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi Standard Deviation
Plan A: No CO_2 Tax	$31.84	$5.16	$5.73
Plan B: Virginia RGGI (unlimited imports)	$34.06	$5.83	$6.36
Plan C: RGGI (unlimited imports)	$35.98	$5.83	$6.36
Plan D: RGGI (limited imports)	$36.36	$5.68	$6.17
Plan E: Federal CO_2 Program	$34.32	$5.53	$5.91

Figure 6.7.5.2 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 10% of Natural Gas at Fixed Price

10% of Natural Gas at Fixed Price				
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Tax	$31.89	$4.74	$5.28	8.2%
Plan B: Virginia RGGI (unlimited imports)	$34.10	$5.47	$5.97	6.1%
Plan C: RGGI (unlimited imports)	$36.01	$5.47	$5.97	6.1%
Plan D: RGGI (limited imports)	$36.39	$5.31	$5.76	6.5%
Plan E: Federal CO_2 Program	$34.35	$5.12	$5.49	7.3%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Figure 6.7.5.3 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 20% of Natural Gas at Fixed Price

20% of Natural Gas at Fixed Price				
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Tax	$31.99	$4.31	$4.80	16.5%
Plan B: Virginia RGGI (unlimited imports)	$34.17	$5.17	$5.66	11.4%
Plan C: RGGI (unlimited imports)	$36.08	$5.12	$5.60	12.1%
Plan D: RGGI (limited imports)	$36.47	$4.95	$5.38	13.0%
Plan E: Federal CO_2 Program	$34.45	$4.72	$5.03	14.6%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Figure 6.7.5.4 – Impact of Fixed Price Natural Gas on Levelized Average Cost and Operating Cost Risk – 30% of Natural Gas at Fixed Price

30% of Natural Gas at Fixed Price				
2018 Plan $/MWh	Expected Levelized Average Cost	Standard Deviation	Semi Standard Deviation	% Reduction in Standard Deviation
Plan A: No CO_2 Tax	$32.15	$3.89	$4.32	24.6%
Plan B: Virginia RGGI (unlimited imports)	$34.29	$4.77	$5.18	18.1%
Plan C: RGGI (unlimited imports)	$36.21	$4.77	$5.18	18.1%
Plan D: RGGI (limited imports)	$36.60	$4.58	$5.00	19.4%
Plan E: Federal CO_2 Program	$34.60	$4.32	$4.59	21.8%

Note: Base volume and fixed market prices established from expected case results of stochastic analysis. Percent reduction in standard deviation relative to Figure 6.7.5.1 – No Gas at Fixed Price analysis.

Included in the analysis of cost and risk mitigation effects of the long-term contracts or reserve investment is an estimate of the price impact the purchase of a large volume of natural gas would have on the market. The cost of such a transaction used in this analysis are representative of the impact on upward price movement that is likely to occur in the market for natural gas with the purchase of a significant quantity of gas on a long-term basis. The market impact of transacting significant volumes on a long-term contract is a function of the amount of time required to execute the contract volume and the price impact/potential movement of the price strip contract during the execution time. The cost of executing a contract of this type is estimated using the price of gas, the daily volatility of the five-year price strip, and the number of days needed to procure the volume. The larger the volume, the longer it takes to execute the transaction, which exposes the total transaction volume to market volatility for a longer period of time and thereby increases the potential for increased cost associated with the transaction. The estimated cost adders included in the analysis are summarized in Figure 6.7.5.5.

Figure 6.7.5.5 – Cost Adders for a Fixed Price Natural Gas Long-Term Contract ($/MMbtu)

		Yearly Volume (Bcf)			
		25	50	75	100
Gas Price	$3.00	$0.08	$0.13	$0.18	$0.23
	$5.00	$0.11	$0.20	$0.28	$0.36
	$7.00	$0.15	$0.26	$0.38	$0.49

The analyzed volumes will have an impact on forward market prices; as such, the Company considers it prudent to include an estimate of the impact of transactions involving large volumes of natural gas on the gas price as a cost adder in this analysis. The Company recognizes the actual impact may be higher or lower than estimated. These costs are presented as representative based on assumptions determined from current market conditions. The salient value to these estimates is the inclusion of estimated market impact verses assuming the transactions can be conducted with no market price impact.

The primary benefit of such a strategy is to mitigate fuel price volatility, not to ensure below market prices. Stable natural gas pricing over the long term does have advantages in terms of rate stability but also carries the risk of higher fuel cost should the market move against the stabilized price. Figures 6.7.5.6 and 6.7.5.7 provide a hypothetical example of stabilizing natural gas price at prevailing market prices available in February 2011 and February 2012, respectively. In this simplified example the assumption is a total fuel volume of 100 million cubic feet (“mmcf”) per day is needed for the entire period. The analysis then evaluates the impact of stabilizing the natural gas price (using February 2, 2011 and February 2, 2012 forward curves) for 20% of the volume against allowing the total volume to be priced at daily market prices. The key parameter is the cumulative difference between programs that stabilize the price of 20% of the natural gas volume while purchasing 80% of the volume at daily market prices versus purchasing all the natural gas at daily market prices for the entire term. In these examples, the cumulative cost of the natural gas purchased by the 20% fixed cost program are higher by 6% to 14% depending on when the contract was established. These examples indicate that although the use of long-term contracts or reserve investments provides an effective method for mitigating fuel prices volatility, it does not ensure lower fuel cost to the customer.

Figure 6.7.5.6 – Hypothetical Example of the Cost of Purchasing 100 MMcf/day of Natural Gas

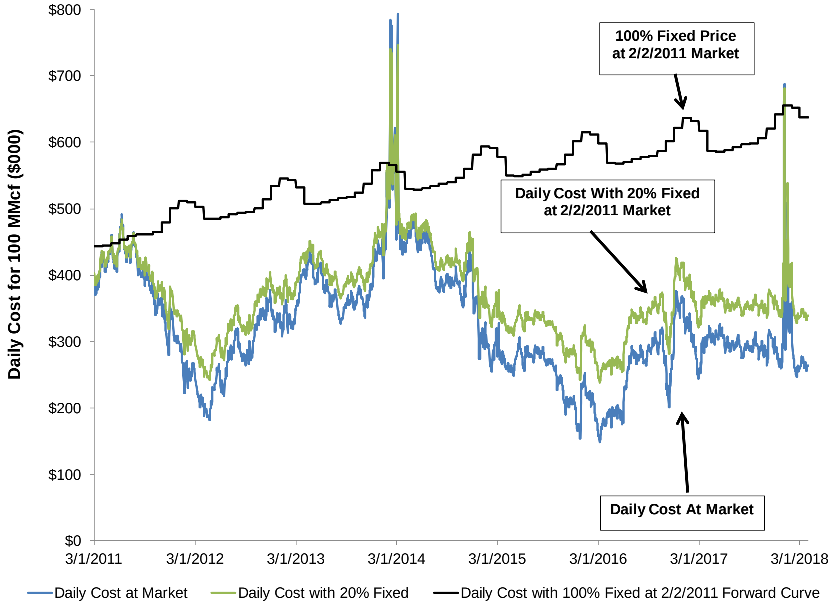
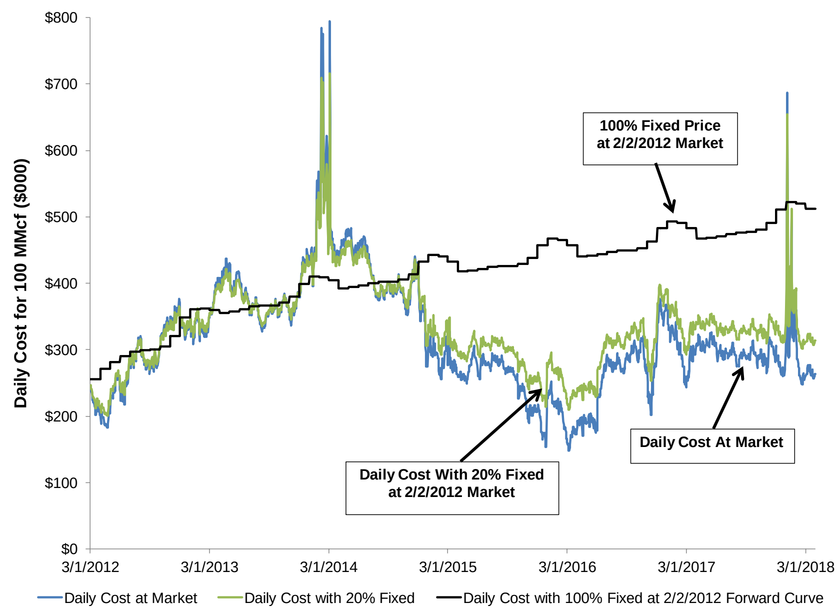


Figure 6.7.5.7 – Hypothetical Example of the Cost of Purchasing 100 MMcf/day of Natural Gas



Firm Transportation

To evaluate the risk mitigation impact of securing long-term firm transportation, historic prices were analyzed at two natural gas supply basin trading hubs, Henry Hub and South Point, and at a natural gas trading hub representative of the Company's service territory, Transco Zone 5. The risk mitigation impact is a function of the difference in volatility between various natural gas trading hubs. Pipeline constraints can limit the ability of the pipeline network to move natural gas from supply basins to the market area. These constraints, coupled with weather-driven demand, have historically resulted in significant location specific price volatility for natural gas. Long-term transportation contracts to various supply basin trading hubs afford the opportunity to mitigate location specific volatility risk by having the option to purchase natural gas at trading hubs that have less volatile pricing characteristics. Figure 6.7.5.8 shows the location of key natural gas trading hubs. Figures 6.7.5.9 through 6.7.5.11 illustrate the historic price variations (2009 to March 2018) for natural gas at three trading hubs. The shaded area of the graphs indicates one standard deviation of pricing history for each year, meaning that 68% of all daily prices for each year fall within the shaded area. As can be seen in these figures, the historic variations in price differ between the three trading hubs with Transco Zone 5 having a higher variation in natural gas prices than the two trading hubs located in supply basins. Based on historic pricing patterns, this would indicate a long-term transportation contract to either Henry Hub or South Point would provide the opportunity to purchase natural gas at a trading hub that has historically experienced less short-term variations in price.

Figure 6.7.5.8 – Map of Key Natural Gas Pipelines and Trading Hubs

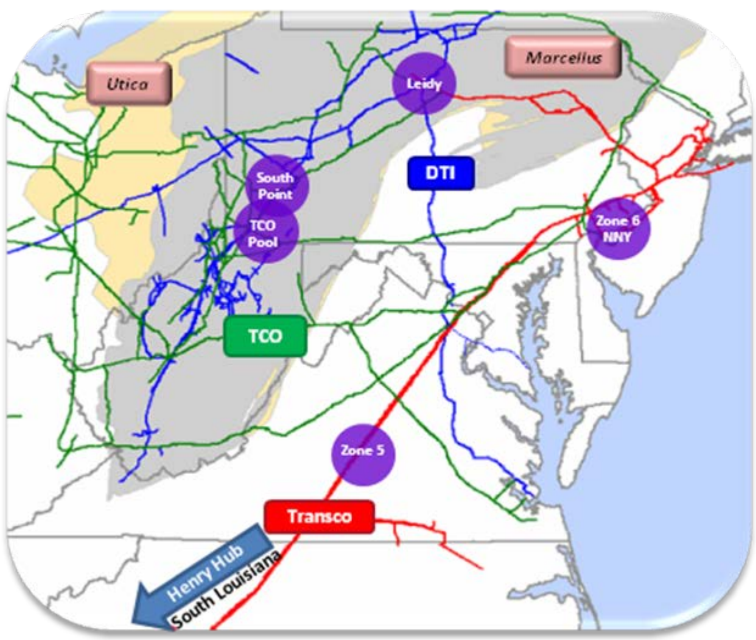
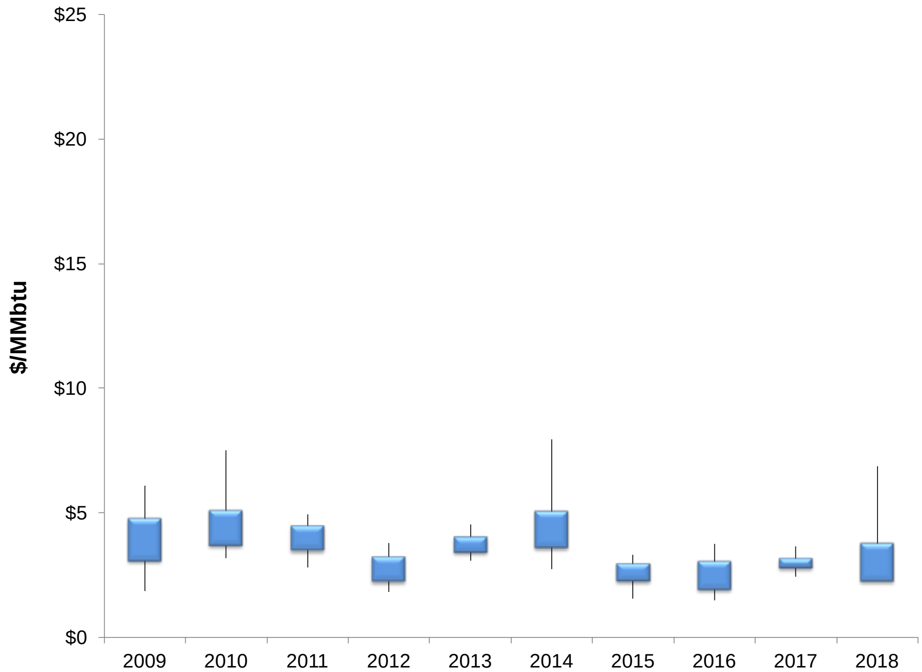
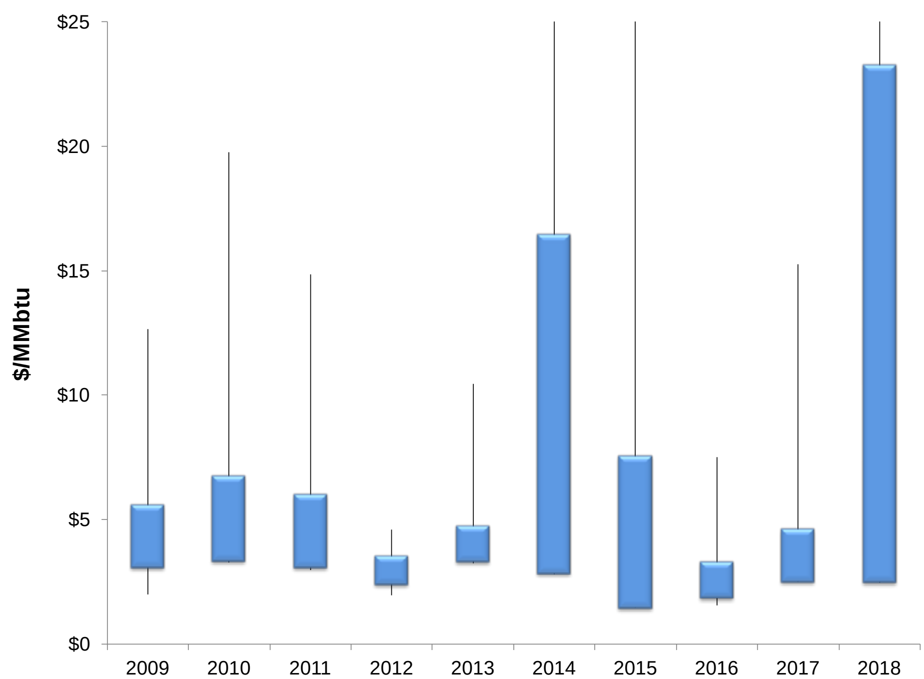


Figure 6.7.5.9 – Natural Gas Daily Average Price Ranges – Henry Hub



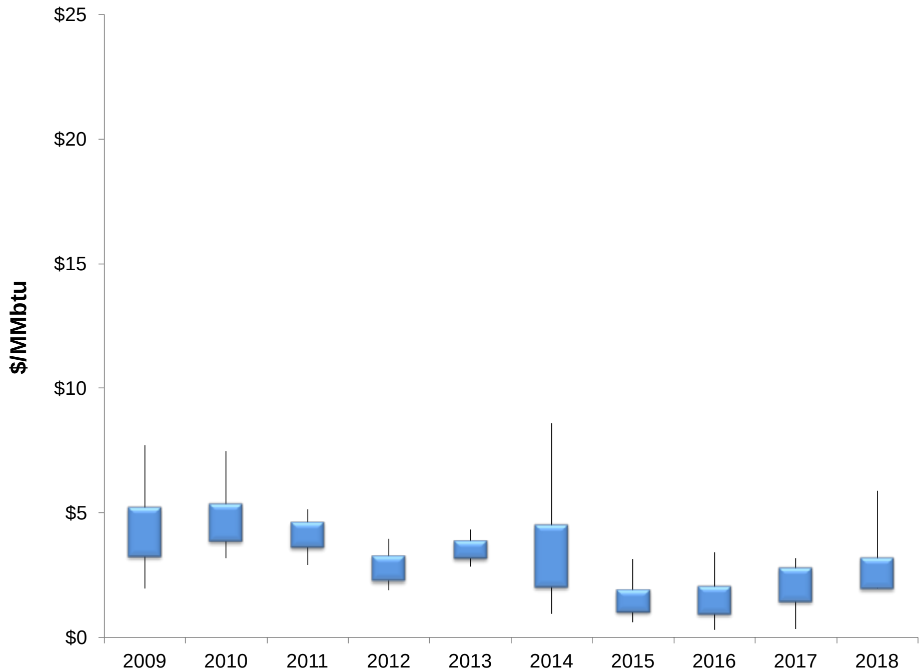
Note: A larger box indicates greater price volatility than a smaller box. Prices through March 31, 2018.

Figure 6.7.5.10 – Natural Gas Daily Average Price Ranges – Transco Zone 5



Note: A larger box indicates greater price volatility than a smaller box. Prices through March 31, 2018.

Figure 6.7.5.11 – Natural Gas Daily Average Price Ranges – South Point



Note: A larger box indicates greater price volatility than a smaller box. Prices through March 31, 2018.

On-site Liquid Natural Gas Storage
On-site liquid natural gas ("LNG") storage provides short periods of plant fueling and requires long refill times. It also serves as a backup fueling arrangement capable of mitigating risk associated with a system-wide pipeline disruption scenario, while providing an option that has operating characteristics similar to natural gas. However, this type of fueling arrangement provides limited operating cost risk mitigation. The natural gas required to fill LNG storage would be supplied using natural gas purchased at market prices with limited assurance that price would be lower during the refill process than when used as a fueling source. LNG storage capacity would generally be large enough to fuel a plant for several days, while taking several months to refill the storage.

6.8 GENERATION UNIT RETIREMENTS

Plans A through E include several generating unit retirements that were necessary to minimize overall costs to the Company's customers or to meet the CO_2 limits required by the program being assessed (i.e., Virginia RGGI, RGGI, and Federal CO_2 Program).

The generators listed below should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date. For purposes of this 2018 Plan, the assumptions regarding generation unit retirements are as follows:

- Bellemeade (267 MW) to be potentially retired by 2021 in all Alternative Plans;
- Bremo Units 3 and 4 (227 MW) to be potentially retired by 2021 in all Alternative Plans;
- Chesterfield Units 3 and 4 (261 MW) to be potentially retired by 2021 in all Alternative Plans;
- Mecklenburg Units 1 and 2 (138 MW) to be potentially retired by 2021 in all Alternative Plans;
- Pittsylvania (83 MW) to be potentially retired by 2021 in all Alternative Plans;

- Possum Point Units 3 and 4 (316 MW) to be potentially retired by 2021 in all Alternative Plans;
- Possum Point Unit 5 (786 MW) to be potentially retired by 2021 in all Alternative Plans;
- Yorktown Unit 3 (790 MW) to be potentially retired by 2022 in all Alternative Plans;
- Chesterfield Units 5 (336 MW) and 6 (670 MW) to be potentially retired by 2023 in Alternative Plans B, C, and D; and
- Clover Units 1 (220 MW) and 2 (219 MW) to be potentially retired by 2025 in Alternative Plans B, C, and D.

6.9 MISCELLANEOUS ANALYSIS

Retire/Co-Fire/Repower Analysis

This analysis was focused on the Company's coal-fired and heavy oil-fired facilities and assessed the cost to customers of the retirement, co-firing natural gas, and repowering of these facilities to exclusively burn natural gas. The analysis was performed using the PLEXOS model and assumed CO_2 limitations and market forecasts consistent with three scenarios: No CO_2 Tax, RGGI, and the Federal CO_2 Program.

The retirement analysis included an assessment of the forecasted unit economics and the cost to customers assuming: (i) continued business operations of these facilities; (ii) the potential retirement of these facilities; (iii) 25% and 100% co-firing natural gas at these facilities; and (iv) repowering these facilities to exclusively burn natural gas. In the case of retirement, this analysis considered the cost of retirement and replacement of these facilities. The co-firing and repowering analysis considered all plant capital costs associated with natural gas fueling along with all pipeline and other fuel costs associated with delivering natural gas to the facility. The co-fire and repower alternatives assumed a commercial operations date of 2020. All co-fire and repower options analyzed resulted in a higher cost compared to unaltered operations of a unit.

Units with negative or marginal value were included as retirements. Virginia coal-fired and heavy oil-fired facilities tended to have less upside potential in the long run under the RGGI scenario. The results of the analysis are included in Figure 6.9.1, as described in Section 6.8 above and shown in each Alternative Plan. A negative sign in Figure 6.9.1 indicates an adverse impact (i.e., increase) on cost to the customer by continuing to operate the unit, while a positive sign indicates a decrease in cost to the customer. No decisions have been finalized concerning these units as work continues to lower costs and verify grid stability.

Figure 6.9.1 – Retirement Analysis Results

Units	No CO_2 Tax	RGGI	Federal CO_2 Program
Chesterfield 5 - 6	+	-	+
Clover 1 - 2	+	Marginal	+
Mt. Storm 1 - 3	+	+	+
Possum Point 5	-	-	-
Yorktown 3	Marginal	-	Marginal

PJM DOM Zone Load Forecast

For the past two years, PJM's load forecast for the DOM Zone has been lower than the Company's load forecast. To show the effect of a lower load forecast on a generation expansion plan, the Company has included an additional analysis in this 2018 Plan. In this analysis, the Company used PJM's load forecast for the DOM Zone that was included in the 2018 PJM Load Forecast Report. This PJM load forecast was run in the PLEXOS model under the No CO_2 Tax scenario provided by

ICF. The optimized results were then compared against the results identified in Plan A: No CO_2 Tax. Figure 6.9.2 reflects the build plan and Figure 6.9.3 reflects the NPV of that comparison. While the Company includes this analysis, it reiterates the issues with PJM's load forecasting methodology discussed in Section 2.3.

Figure 6.9.2 – PJM Low Load Build Plan

Year	Plan A: No CO_2 Tax	No CO_2 Tax (PJM Low Load)
Approved DSM: 304 MW, 805 GWh by 2033		
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)
2025	CT SLR (400 MW)	SLR (320 MW)
2026	CT SLR (480 MW)	SLR (480 MW)
2027	CT SLR (480 MW)	
2028	SLR (480 MW)	CT
2029		SLR (80 MW)
2030	CT	CT
2031	CT SLR (160 MW)	SLR (80MW)
2032	CT SLR (240 MW)	CT
2033	SLR (80 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CH: Chesterfield Power Station; CT: Combustion Turbine (2 units); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.
2) These units entered into cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These units are planned to enter cold reserve in December 2018.

Figure 6.9.3 – Low Load NPV Comparison

	No CO_2 Tax (PJM Low Load)
NPV Compliance Cost ($B)	$ (3.35)

6.10 2018 PLAN

As discussed in Chapter 1, the uncertainty with respect to the timing and form of CO_2 regulation at the federal level remains high. Although Virginia is actively pursuing regulations and has proposed a state program linked to RGGI, a final regulation is not expected until later this year. Until the rules that will be applicable to Virginia are certain, it is difficult to recommend a specific long-term plan. Therefore, as mentioned in Chapter 1, the 2018 Plan offers no "Preferred Plan" and no recommended long-term path forward other than the guidance offered in the STAP discussed in Chapter 7.

Rather, this 2018 Plan offers the Alternative Plans for consideration, each of which may be a likely path forward once the uncertainty of GHG regulation is resolved. Plan A offers a path forward should no CO_2 regulations be adopted of any kind. Plans B through E each identify plans that are compliant with a possible form of RGGI or a Federal CO_2 Program that, based on ICF's view, may occur in the future. Collectively, this analysis and presentation of the Alternative Plans, along with the decision to pursue the STAP, comprises the 2018 Plan.

CHAPTER 7 – SHORT-TERM ACTION PLAN

The STAP provides the Company's strategic plan for the next five years (2019 to 2023), as well as a discussion of the specific short-term actions the Company is taking to meet the initiatives discussed in this 2018 Plan. The Company continues to proactively position itself in the short-term to address the evolving developments surrounding future CO_2 emission mitigation rules or regulations, or societal and customer preferences for the benefit of all stakeholders over the long term. Over the next five years, the Company expects to:

- Continue development of planning processes that will reasonably assess the actions and costs associated with the integration of large volumes of intermittent renewable generation on the transmission and distribution networks;
- Enhance and upgrade the Company's existing transmission and distribution grid;
- Enhance the Company's access to natural gas supplies, including shale gas supplies from multiple supply basins;
- Construct additional generation while maintaining a balanced fuel mix;
- Continue to lower the Company's emissions footprint;
- Continue to develop and implement a renewable strategy that supports the Virginia RPS goals and the North Carolina REPS requirements;
- Implement cost-effective programs based on measures identified in the 2017 DSM Potential Study and continue to implement cost-effective DSM programs in Virginia and North Carolina (DSM provisions of the GTSA will be reflected in future plans after the completion of the stakeholder process required in the Act);
- Continue to evaluate potential unit retirements in light of changing market conditions and regulatory requirements;
- Enhance reliability and customer service;
- Continue development of the CVOW facility; and
- Continue analysis and evaluations for the 20-year nuclear license extensions for Surry Units 1 and 2, and North Anna Units 1 and 2.

7.1 DIFFERENCES IN THE STAP FROM THE 2017 PLAN TO THE 2018 PLAN

Figure 7.1.1 displays the differences between the 2017 STAP and the 2018 STAP.

Figure 7.1.1 - Changes between the 2017 and 2018 Short-Term Action Plans

Year	Supply-side Resources					Demand-side Resources[1]
	New Conventional	New Renewable	Retrofit	Cold Storage	Retire	
2018		SLR NUG		Belle[2], Bremo 3&4[2], CH 3&4[4], MB 1&2[2], Pitt[3], PP 3&4[4]	YT 1&2[5]	Approved DSM
2019	Greensville	SLR NUG[6]	~~PP5 - SNCR~~			
2020		US-3 Solar 1 SLR				
2021		US-3 Solar 2 SLR CVOW[7]			Belle, Bremo 3&4 CH 3&4, MB 1&2, Pitt PP 3-5	
2022	CT	SLR			~~CH 3&4~~, YT3	
2023	CT	SLR				

Key: Retrofit: Additional environmental control reduction equipment; Retire: Remove a unit from service; Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CH: Chesterfield Power Station; US-3 Solar 1: US-3 Solar 1 Facility; CVOW: Coastal Virginia Offshore Wind Project; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SNCR: Selective Non-Catalytic Reduction; SLR NUG: Solar NUG; SLR: Generic Solar: US-3 Solar 2: US-3 Solar 2 Facility; YT: Yorktown Power Station.

Color Key: Blue: Updated resource since 2017 Plan; Red with Strike: 2017 Plan resource replacement; Black: No change from 2017 Plan.

Note: 1) DSM capacity savings increases throughout the Planning Period.
2) These generating units entered cold reserve in April 2018.
3) Pittsylvania is planned to enter cold reserve in August 2018.
4) These generating units are planned to enter cold reserve in December 2018.
5) Yorktown Units 1 and 2 ceased operations on April 15, 2017 to comply with the MATS rule. They are now available for emergency operation per PJM.
6) Solar NUG capacity changed to 760 MW total in VA and NC.
7) 12 MW (nameplate) CVOW was previously referred to as VOWTAP in the 2017 Plan.

A more detailed discussion of the activities over the next five years is provided in the following sections.

7.2 GENERATION RESOURCES

Over the next five years, the Company expects to take the following actions related to existing and proposed generation resources:

- Place the Greensville County Power Station (1,585 MW), approved on March 29, 2016, into service by 2019;
- Continue technical evaluations and aging management programs required to support a second license extension of the Company's existing Surry Units 1 and 2 and North Anna Units 1 and 2; and
- Submit an application for the second renewed operating licenses for Surry Units 1 and 2 by the end of the first quarter of 2019 and for North Anna Units 1 and 2 by the end of 2020.

Figure 7.2.1 lists the generation plants that are currently under construction and are expected to be operational by 2023. Figure 7.2.2 lists the generation plants that are currently under development and are expected to be operational by 2023 subject to SCC approval.

Figure 7.2.1 - Generation under Construction

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

Note: 1) Commercial Operation Date.

Figure 7.2.2 - Generation under Development[1]

Forecasted COD	Unit	Location	Primary Fuel	Unit Type	Nameplate Capacity (MW)	Summer Capacity (Net MW)	Winter Capacity (Net MW)
2020	US-3 Solar 1	VA	Solar	Intermittent	142	33	33
2021	US-3 Solar 2	VA	Solar	Intermittent	98	22	22
2021	CVOW	VA	Wind	Intermittent	12	2	2
Ongoing	Surry Unit 1 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
Ongoing	Surry Unit 2 Nuclear Extension	VA	Nuclear	Baseload	838	838	875
Ongoing	North Anna Unit1 Nuclear Extension	VA	Nuclear	Baseload	838	838	868
Ongoing	North Anna Unit 2 Nuclear Extension	VA	Nuclear	Baseload	834	834	863

Note: 1) All Generation under Development projects and planned capital expenditures are preliminary in nature and subject to regulatory and/or Board of Directors approvals.

7.3 RENEWABLE ENERGY RESOURCES

Approximately 533 MW of qualifying renewable generation is currently in operation. Over the next five years, the Company expects to take the following actions regarding renewable energy resources:

Virginia

- Achieve 61 MW of biomass capacity at VCHEC by 2023;
- Meet its targets under the Virginia RPS Program by applying renewable generation from existing qualified facilities and purchasing cost-effective RECs;
- Submit its Annual Report to the SCC detailing its efforts towards the RPS plan;
- Apply for SCC approval of US-3 Solar 1 and US-3 Solar 2 Facilities in 2018;
- Continue development of CVOW; and
- Continue development of solar PV resources consistent with the generic solar facilities included in Figure 7.3.1.

North Carolina

- Submit its 2018 REPS Compliance Report for compliance year 2017 in August 2018;
- Submit its annual REPS Compliance Plan (filed as North Carolina Plan Addendum 1 to this 2018 Plan); and
- Enter into or negotiate PPAs with approximately 660 MW (nameplate) of North Carolina solar NUGs by 2020.

Figure 7.3.1 lists the Company's renewable resources included in all Alternative Plans for the next five years.

Figure 7.3.1 - Renewable Resources by 2023

Resource	Nameplate MW
Existing Resources[1]	533
VCHEC Biomass	61
Solar NUGs[2]	760
CVOW	12
US-3 Solar 1	142
US-3 Solar 2	98
Solar 2020	320
Solar 2021	400
Solar 2022	480
Solar 2023	480

Note: 1) Existing Resources include hydro, biomass (excluding VCHEC), and solar.
2) Solar NUGs include forecasted VA and NC solar NUGs through 2020.

7.4 TRANSMISSION

Virginia

The following planned Virginia transmission projects detailed in Figure 7.4.1 are pending SCC approval or are tentatively planned for filing with the SCC:

- Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230kV Lines and New 230kV Substation;
- Line #217 Chesterfield to Lakeside Rebuild;
- Line #549 Dooms to Valley Rebuild;
- Line #112 Fudge Hollow to Lowmoor Partial Rebuild;
- Line #231 Landstown to Thrasher Rebuild;
- Line #211 and Line #228 Chesterfield to Hopewell Partial Rebuild;
- Line #550 Mount Storm to Valley Rebuild;
- Line #2189 Glebe to Potomac River – New 230 kV Line;
- Line #2175 Idylwood to Tysons – New 230 kV Line and New 230 kV Tysons Substation;
- Line #205 and Line #2003 Chesterfield to Tyler Partial Rebuild; and
- Line #247 Suffolk to Swamp Rebuild.

Figure 7.4.1 lists the major transmission additions including line voltage, capacity, and expected operation target dates.

Figure 7.4.1 - Planned Transmission Additions

Line Terminals	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #47 Kings Dominion to Fredericksburg Rebuild	115	353	May-18	VA
Line #4 Bremo to Cartersville Uprate	115	151	May-18	VA
Line #2183 Brambleton to Poland Road – New 230 kV Line and New 230 kV Substation	230	1,047	May-18	VA
Line #2174 Vint Hill to Wheeler – New 230 kV Line	230	1,047	Jun-18	VA
Line #553 Cunningham to Elmont Rebuild	500	4,330	Jun-18	VA
Line #1009 Ridge Road to Chase City Rebuild	115	346	Jun-18	VA
Line #1020 Pantego to Trowbridge – New 115 kV Line	115	346	Jun-18	NC
Line #1015 Scotland Neck to South Justice Branch – New 115 kV Line	115	346	Sep-18	NC
Line #2086 Remington Combustion Turbine to Warrenton Rebuild	230	1,047	Oct-18	VA
Line #48 Sewells Point to Thole Street and Line #107 Oakwood to Sewells Point Partial Rebuild	115	317 (#48) 353 (#107)	Dec-18	VA
Line #585 Carsons to Rogers Road Rebuild	500	4,330	Dec-18	VA
Line #54 Carolina to Woodland Reconductor	115	174	Dec-18	NC
Line #2161 Wheeler to Gainesville Uprate	230	1,047	Dec-18	VA
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild	115	353 (#34)	May-19	VA
Line #582 Surry to Skiffes Creek – New 500 kV Line	500	4,330	May-19	VA
Line #159 Acca to Hermitage Reconductor	115	353	May-19	VA
Line #2138 Skiffes Creek to Whealton – New 230 kV Line	230	1,047	May-19	VA
Line #171 Chase City to Boydton Plank Road Rebuild	115	393	Jun-19	VA
Line #534 Cunningham to Dooms Rebuild	500	4,330	Jun-19	VA
Line #82 Everetts to Leggetts Crossroads Delivery Point Rebuild	115	353	Dec-19	NC
Line #166 and Line #67 Greenwich to Burton Rebuild	115	353	Dec-19	VA
Line #90 Carolina to Kerr Dam Rebuild	115	346	Dec-19	VA/NC
Line #130 Clubhouse to Carolina Rebuild	115	394	Dec-19	VA/NC
Line #65 Norris Bridge Rebuild	115	147	Dec-19	VA
Line #18 Possum Point to Smoketown and Line #145 Smoketown to Possum Point Rebuild	115	524	Dec-19	VA
Line #547 Bath County to Lexington Series Capacitor Upgrade	500	3,397	Apr-20	VA
Line #548 Bath County to Valley Series Capacitor Upgrade	500	3,397	Apr-20	VA
Line #2153 Remington to Gordonsville – New 230 kV Line	230	1,047	Jun-20	VA
Line #217 Chesterfield to Lakeside Rebuild	230	1,047	Jun-20	VA
Line #549 Dooms to Valley Rebuild	500	4,330	Jun-20	VA
Line #112 Fudge Hollow to Lowmoor Partial Rebuild	138	314	Oct-20	VA
Line #154 Twittys Creek to Pamplin Rebuild	115	353	Dec-20	VA
Line #76 and Line #79 Yorktown to Peninsula Rebuild	115	346	Dec-20	VA
Line #231 Landstown to Thrasher Rebuild	230	1,046	Dec-20	VA
Line #211 and Line #228 Chesterfield to Hopewell Partial Rebuild	230	477	Dec-20	VA
Line #550 Mount Storm to Valley Rebuild	500	4,330	Jun-21	VA
Line #2176 Gainesville to Haymarket and Line #2169 Haymarket to Loudoun – New 230 kV Lines and New 230 kV Substation	230	1,047	Jul-21	VA
Line #127 Buggs Island to Plywood Rebuild	115	353	Dec-21	VA
Line #120 Dozier to Thompsons Corner Partial Rebuild	115	346	Dec-21	VA
Line #16 Great Bridge to Hickory and Line #74 Chesapeake Energy Center to Great Bridge Rebuild	115	353	Dec-21	VA
Line #2175 Idylwood to Tysons – New 230 kV Line and Tysons Substation Rebuild	230	1,047	Jun-22	VA
Line #2001 Possum Point to Occoquan Reconductor and Uprate	230	1,047	Jun-22	VA
Line #227 Beaumeade to Brambleton – Cut-in Belmont Substation	230	1,057	Jun-22	VA
Line #29 Fredericksburg to Possum Point Partial Rebuild	115	361	Dec-22	VA
Line #205 and Line #2003 Chesterfield to Tyler Partial Rebuild	230	1,047	Dec-22	VA
Line #247 Suffolk to Swamp Rebuild	230	1,047	Dec-22	VA/NC
Line #2144 Winfall to Swamp Rebuild	230	1,047	Dec-22	NC
Line #101 Mackeys to Creswell Rebuild	115	262	Dec-22	NC
Line #43 Staunton to Harrisonburg Rebuild	115	262	Dec-22	VA
Line #2189 Glebe to Potomac River – New 230 kV Line	230	900	2022	VA

7.5 DEMAND-SIDE MANAGEMENT

The Company continues to evaluate the measures identified in the 2017 DSM Potential Study and may include additional measures in DSM programs in future Plans. The measures included in the 2017 DSM Potential Study still need to be part of a program design effort that looks at the viability of the potential measures as a single or multi-measure DSM program. These fully-designed DSM programs would also need to be evaluated for cost effectiveness. Under the GTSA, which will become law on July 1, 2018, the Company will propose energy efficiency programs with projected costs of at least $870 million for the period beginning July 1, 2018, and ending July 1, 2028, including its existing approved energy efficiency programs. This legislation included requirements for a new stakeholder process, as discussed further in Section 7.6. The Company will work through that process to develop future programs for filing.

Virginia

The Company will continue its analysis of future programs and may file for approval of new or revised programs that meet the Company requirements for new DSM resources. The Company filed its "Phase VII" DSM Application in October 2017, seeking approval of an extension of the Phase IV Residential Income and Age Qualifying Home Improvement Program (Case No. PUR-2017-00129). The SCC is expected to issue its Final Order in this case by June 2018.

North Carolina

The Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that have been approved in Virginia that continue to meet the Company requirements for new DSM resources. On July 28, 2017, the Company filed in Docket No. E-22, Sub 543 for NCUC approval of the Non-Residential Prescriptive Program that was approved in Virginia in Case No. PUE-2016-00111. On October 16, 2017, the NCUC approved this new DSM program, which has been available to qualifying North Carolina customers since January 2018.

Figure 7.5.1 lists the projected demand and energy savings by 2023 from the approved DSM programs.

Figure 7.5.1 - DSM Projected Savings By 2023

Program	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Air Conditioner Cycling Program	91	-	Approved / Approved
Residential Low Income Program	2	10	Completed / Completed
Residential Lighting Program	-	-	
Commercial Lighting Program	-	1	Closed / Closed
Commercial HVAC Upgrade	1	6	
Non-Residential Distributed Generation Program	11	-	Extension Approved / Rejected
Non-Residential Energy Audit Program	-	2	Completed / Completed
Non-Residential Duct Testing and Sealing Program	11	68	
Residential Bundle Program	11	52	
Residential Home Energy Check-Up Program	6	34	
Residential Duct Sealing Program	-	1	
Residential Heat Pump Tune Up Program	-	-	
Residential Heat Pump Upgrade Program	5	17	Extension Rejected / Completed
Non-Residential Window Film Program	42	46	Approved / Approved
Non-Residential Lighting Systems & Controls Program	34	213	
Non-Residential Heating and Cooling Efficiency Program	47	127	
Income and Age Qualifying Home Improvement Program	3	14	Extension Under Consideration / Suspended
Residential Appliance Recycling Program	1	10	Completed
Small Business Improvement Program	17	64	Approved / Approved
Residential Retail LED Lighting Program (NC only)	1	7	No Plans / Approved
Non-Residential Prescriptive Program	32	217	Approved / Approved

7.6 GTSA COMPLIANCE

In the 2017 Plan Final Order, the SCC directed the Company to include in future filings "detailed plans to implement the mandates contained in [the GTSA]." Figure 7.6.1 provides a list of "mandates" and the accompanying citation to the GTSA. The sections that follow outline these mandates and detail the Company's plans related to each one over the five-year STAP period. It should be noted that several provisions of the GTSA encourage specific public policies, such as greater deployment of renewable energy, without taking the form of a mandate.

Figure 7.6.1 – GTSA Mandates

Mandate	Citation
Evaluate in future Plans: (i) electric grid transformation projects, (ii) energy efficiency measures, and (iii) combined heat and power or waste heat to power	Va. Code § 56-599; EC 12; EC 18
Adjust rates to reflect the reduction in corporate income taxes	EC 6; EC 7
Provide one-time, voluntary bill credits	EC 4; EC 5
Offer Manufacturing and Commercial Competitiveness Retention Credit	EC 11
File triennial review	Va. Code § 56-585.1; Va. Code § 56-585.1:1
Report on potential improvements to renewable programs	EC 17
Report on economic development activities	EC 16
Report on the feasibility of providing broadband using utility infrastructure	EC 13
Report on energy efficiency programs	EC 15
Fund energy assistance and weatherization pilot program	Va. Code § 56-585.1:2
Propose a plan to deploy 30 MW of battery storage under new pilot program	EC 9; EC 10
Propose a plan for electric distribution grid transformation projects	Va. Code § 56-585.1 A 6
Propose a plan for energy conservation measures with a projected cost of no less than $870 million	EC 15

Plan-Related Mandates

The GTSA amends Va. Code § 56-599 to require the Company to evaluate electric grid transformation projects and energy efficiency measures. While these new provisions do not take effect until July 1, 2018, the Company discusses its plans related to these provisions below.

The GTSA also requires the Company to include specific analysis in its future Plans. Specifically, Enactment Clause ("EC") 18 requires certain analysis related to energy efficiency measures, and EC 12 requires consideration of combined heat and power or waste heat to power measures or generation alternatives. The Company plans to include this required analysis in its next Plan.

Rate-Related Mandates

The GTSA contains a number of mandates related to customer rates. First, the Company must reduce its rates for generation and distribution services to reflect the reduction in corporate income taxes under the federal Tax Cuts and Jobs Act of 2017 (the "TCJA"). As set forth in EC 7 of the GTSA, the Company plans to "reduce its existing rates for generation and distribution services on an interim basis, within 30 days of July 1, 2018, in an amount sufficient to reduce its annual revenues from such rates by an aggregate amount of $125 million." The Company will then provide the SCC with the necessary information to "true-up . . . this interim reduction amount to the actual annual reduction in corporate tax obligations of [the Company] as of the effective date of the [TCJA]," as set forth in EC 6. In carrying out these mandates, the Company will comply with the SCC's April 16, 2018 Order in Case No. PUR-2018-00055.

Second, the Company must issue one-time, voluntary generation and distribution services bill credits. As set forth in EC 4 of the GTSA, the Company plans to "no later than 30 days following July 1, 2018, . . . provide to its current customers a one-time, voluntary generation and distribution services bill credit, to be allocated on a historic test period energy usage basis, in an aggregate amount of $133 million." Then, as set forth in EC 5, the Company plans to "no later than 30 days after January 1, 2019, . . . provide to its current customers a one-time, voluntary generation and distribution services bill credit, to be allocated on a historic test period energy usage basis, in an aggregate amount of $67 million." In carrying out these madates, the Company will comply with the SCC's April 16, 2018 Order in Case No. PUR-2018-00053.

Next, the GTSA requires the Company to provide the Manufacturing and Commercial Competitiveness Retention Credit to eligible customers. The Company plans to offer this credit to eligible customers.

Finally, the GTSA outlines the structure through which Company rates will be set going forward. The Company plans to make a triennial review filing by March 31, 2021.

Mandated Reports

The GTSA next includes a list of reports that the Company must file with the SCC and others. Figure 7.6.2 provides a list of required reports. The Company plans to file these mandated reports by the statutory deadline.

Figure 7.6.2 – GTSA Mandated Reports

Report	Deadline	Citation
Report on potential improvements to renewable programs	November 1, 2018	EC 17
Report on economic development activities	December 1, 2018	EC 16
Report on the feasibility of providing broadband using utility infrastructure	December 1, 2018	EC 13
Report on energy efficiency programs	July 1, 2019 (then annually)	EC 15

Pilot Program Mandates

The GTSA contains two mandates related to pilot programs. First, under the amended language in Va. Code § 56-585.1:2, the Company must continue its pilot program for energy assistance and weatherization for low income, elderly, and disabled individuals "at no less than $13 million for each year the utility is providing such service." The Company plans to continue this pilot program and will develop a plan to meet the required funding.

Second, the GTSA requires the SCC to establish a pilot program for storage batteries. The GTSA mandates that the Company submit a proposal to deploy up to 30 MW of batteries. The Company plans to submit a proposal compliant with the GTSA and with the rules and guidelines to be established by the SCC.

Mandate Related to Electric Distribution Grid Transformation Projects

EC 15 of the GTSA mandates that the Company "petition the SCC, not more than once annually, for approval of a plan for electric distribution grid transformation projects." The GTSA defines "electric distribution grid transformation projects" as follows:

> "Electric distribution grid transformation project" means a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information.

The Company plans to file a grid transformation plan by the end of 2018.

Mandate Related to Energy Conservation Measures

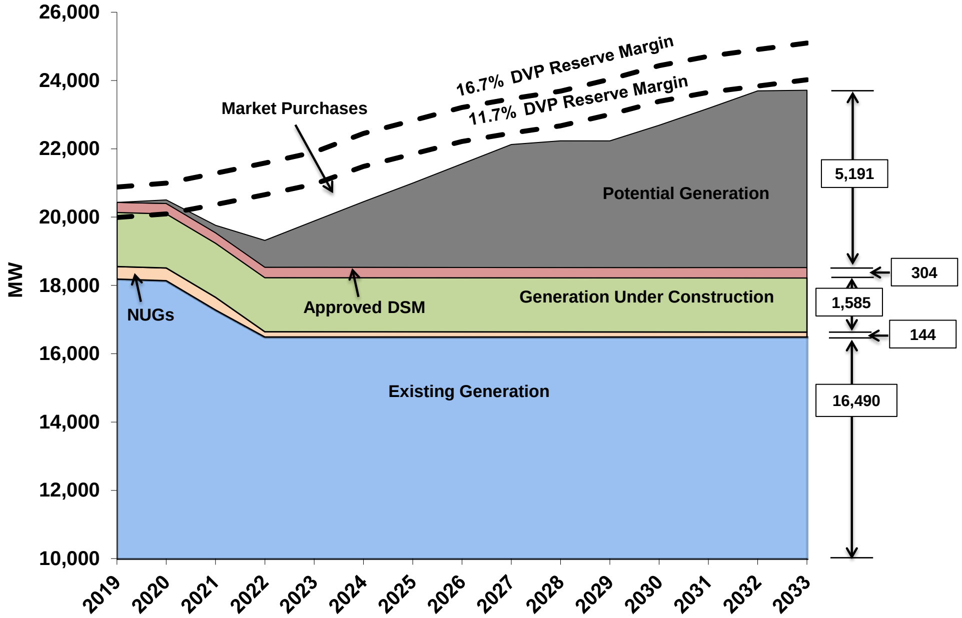
EC 15 of the GTSA directs the Company to develop a proposed program of energy conservation measures with a projected cost of no less than $870 million for the period beginning July 1, 2018, and ending July 1, 2028. At least five percent of the proposed programs must benefit low-income, elderly, and disabled individuals. The program must provide for the submission of "petitions for approval to design, implement, and operate energy efficiency programs" under Va. Code § 56-585.1 A 5 c. In developing these programs, the Company must utilize a stakeholder process to receive input and feedback on the development of its energy efficiency programs. The stakeholder process will be facilitated by an independent monitor compensated under the funding provided pursuant to Va. Code § 56-592.1 E, and will include representatives from the SCC, the Attorney General's Office of Consumer Counsel, the Department of Mines, Minerals and Energy, energy efficiency program implementers, energy efficiency providers, residential and small business customers, and any other interested stakeholder who the independent monitor deems appropriate for inclusion. As noted above, the Company must submit an annual report on the status of these programs beginning July 1, 2019.

See Section 5.5 and 7.4 for more details on the Company's current plans for future DSM initiatives. Going forward, the Company plans to develop a proposed program of energy conservation measures as directed by the GTSA using its current plans and past experiences with its DSM programs. The Company plans to utilize the stakeholder process, once established pursuant to Va. Code § 56-592.1 E, to develop its energy efficiency programs as required.

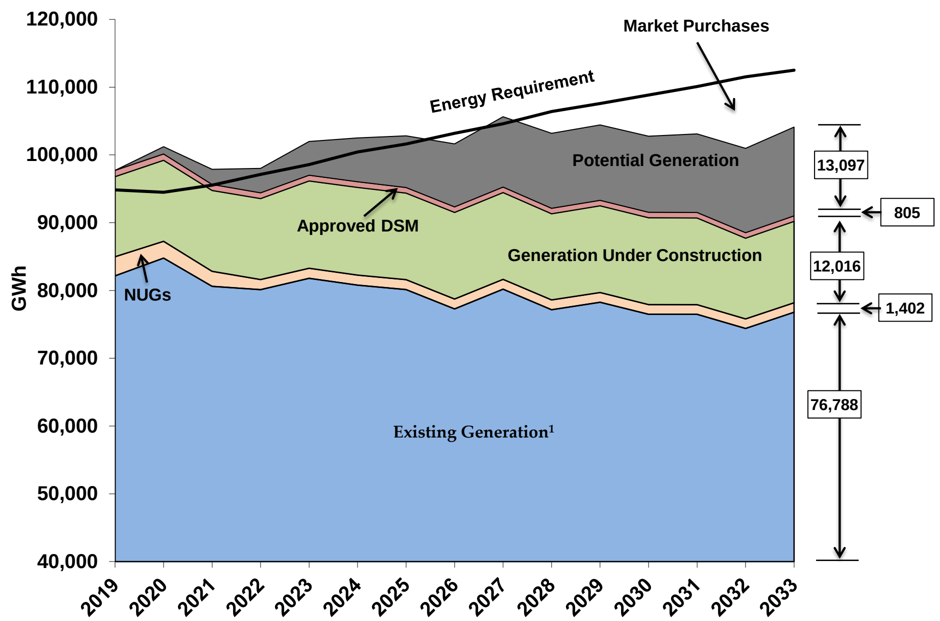
APPENDIX

Appendix 1A – Plan A: No CO_2 Tax – Capacity & Energy

Capacity



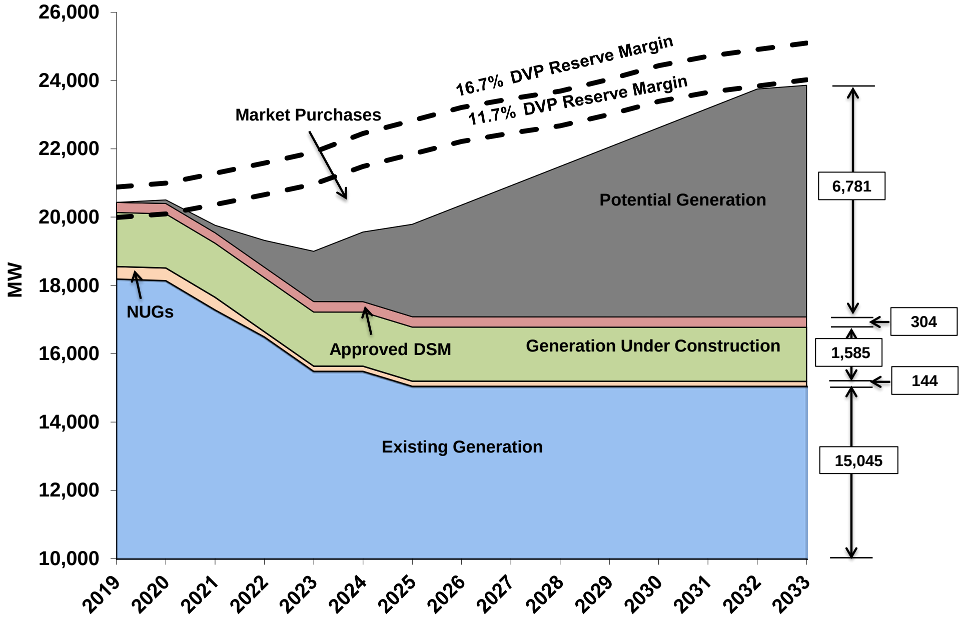
Energy



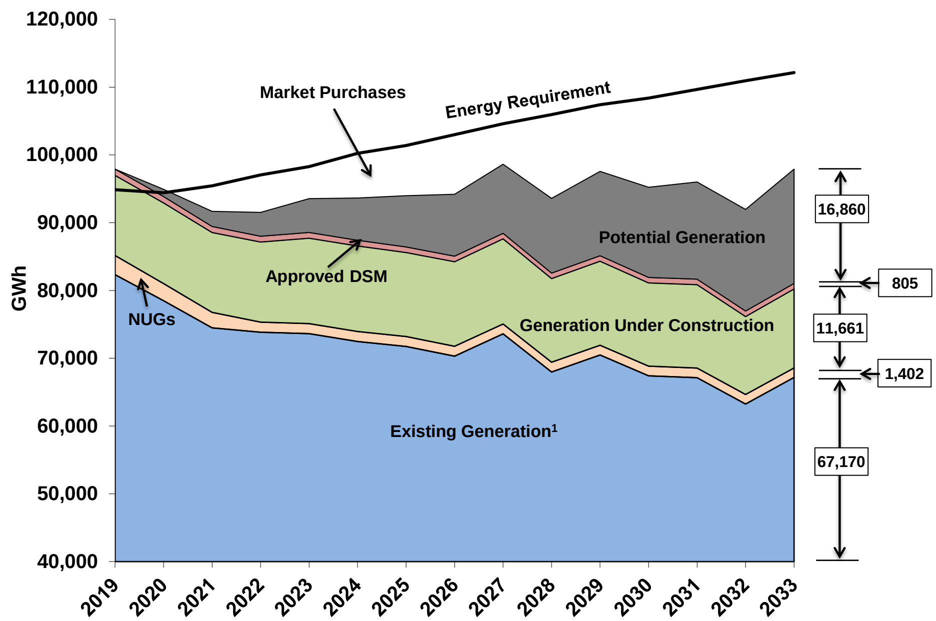
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan B: Virginia RGGI (unlimited imports) – Capacity & Energy

Capacity



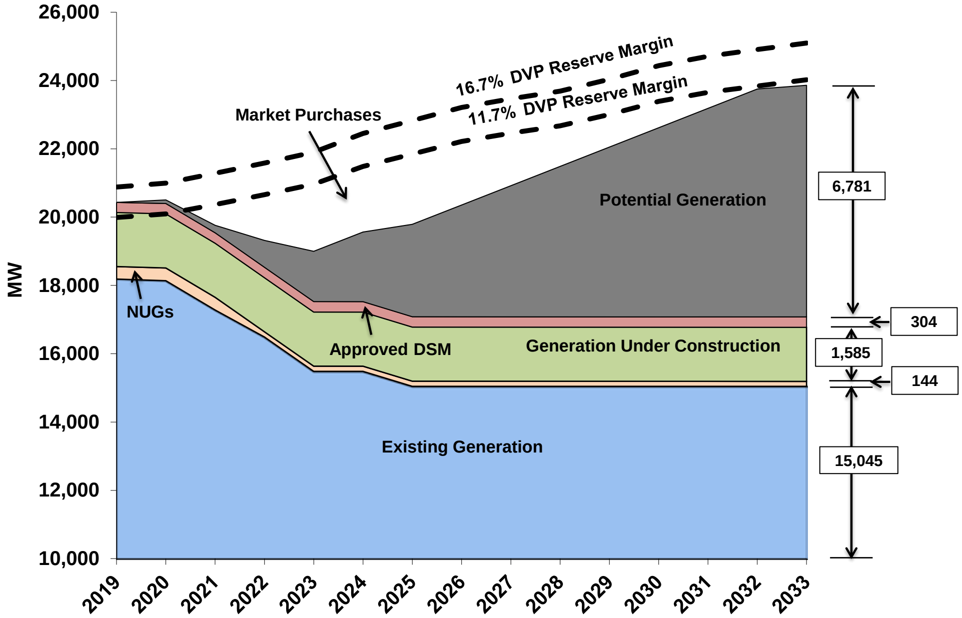
Energy



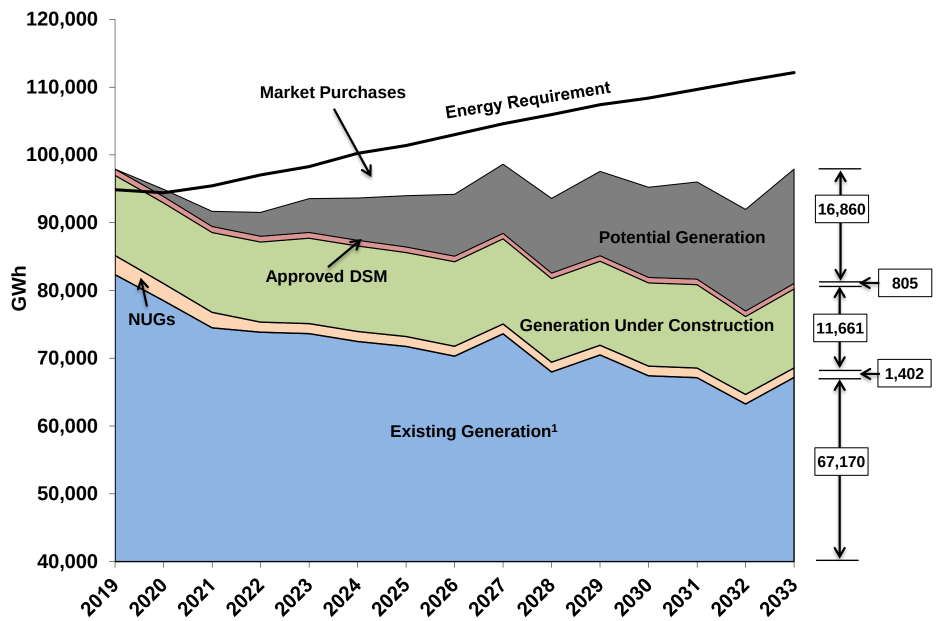
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan C: RGGI (unlimited imports) – Capacity & Energy

Capacity



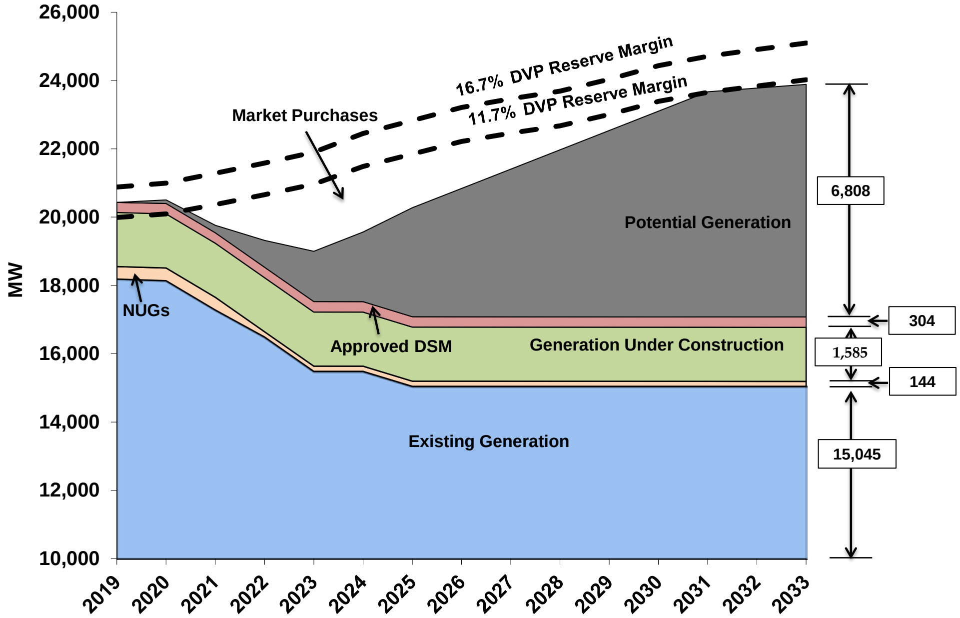
Energy



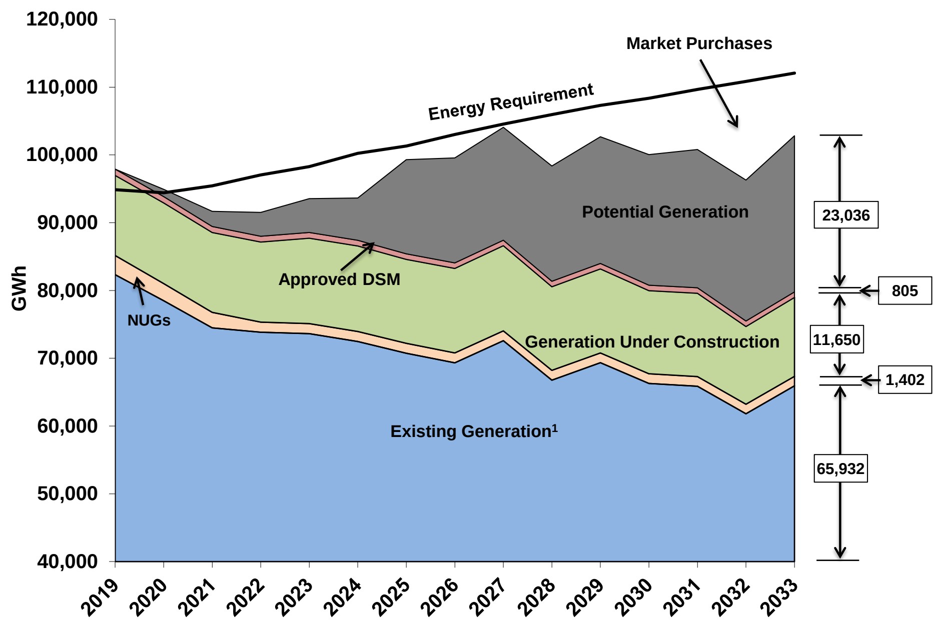
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan D: RGGI (limited imports) – Capacity & Energy

Capacity



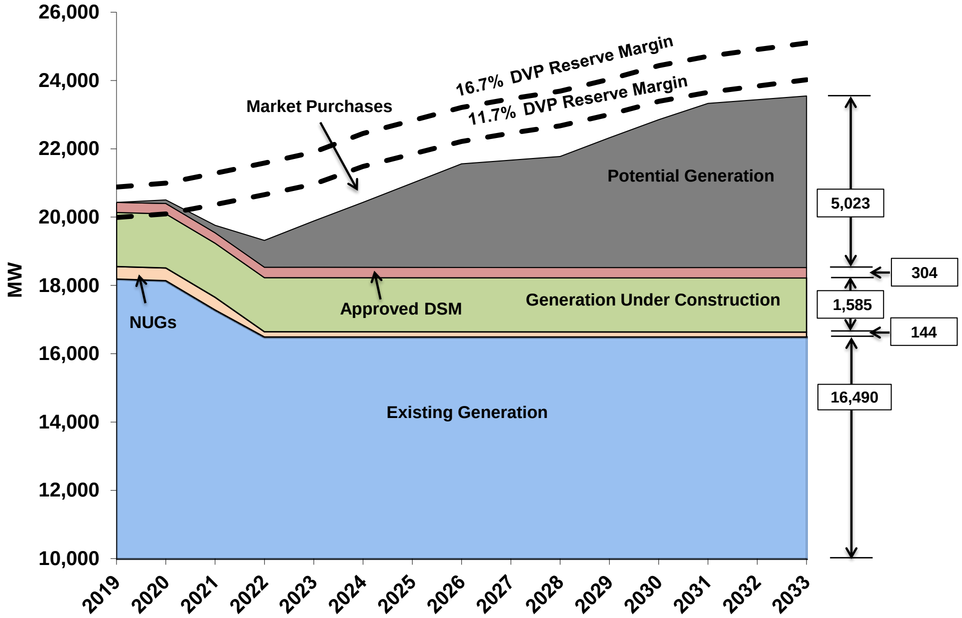
Energy



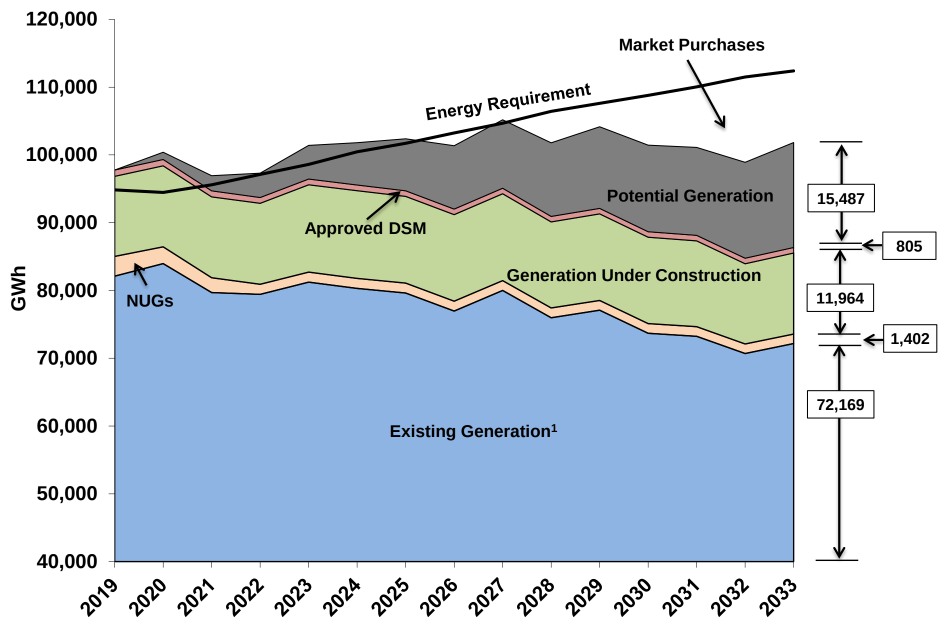
Note: 1) Accounts for potential unit retirements and rating changes to existing units in the Plan, and reflects summer ratings.

Appendix 1A – Plan E: Federal CO_2 Program – Capacity & Energy

Capacity



Energy



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

Appendix 1B – CPP Scenario

As stated earlier in this 2018 Plan, the Company no longer believes the CPP to be a “current” or “pending” regulation. As such, the Company has not included a CPP scenario as part of the Alternative Plans. The Company has included, however, a single CPP assessment. In this case, the Company determined the optimized generation expansion plan should the U.S. adopt CO_2 regulations consistent with the CPP. This evaluation assumed a mass-based program for Virginia that regulated existing and new generation as that term is defined in the CPP.

The figures below reflect the build plan and NPV of the CPP scenario as compared to Plan A: No CO_2 Tax.

Year	Plan A: No CO_2 Tax	CPP Scenario
Approved DSM: 304 MW, 805 GWh by 2033		
2019	Greensville SLR NUG(1)	Greensville SLR NUG(1)
2020	US-3 Solar 1 SLR (320 MW)	US-3 Solar 1 SLR (320 MW)
2021	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5	CVOW US-3 Solar 2 SLR (400 MW) Belle(2), Bremo3-4(2) CH3-4(4), MB1-2(2) Pitt(3), PP3-4(4) PP5
2022	CT SLR (480 MW) YT3	CT SLR (480 MW) YT3
2023	CT SLR (480 MW)	CT SLR (480 MW)
2024	CT SLR (480 MW)	CT SLR (480 MW)
2025	CT SLR (400 MW)	CT SLR (400 MW)
2026	CT SLR (480 MW)	CT SLR (480 MW)
2027	CT SLR (480 MW)	CT SLR (480 MW)
2028	SLR (480 MW)	CT SLR (480 MW)
2029		SLR (480 MW)
2030	CT	CT SLR (480 MW)
2031	CT SLR (160 MW)	SLR (480 MW)
2032	CT SLR (240 MW)	CT
2033	SLR (80 MW)	SLR (480 MW)

Key: Belle: Bellemeade Power Station; Bremo: Bremo Power Station; CH: Chesterfield Power Station; CT: Combustion Turbine (2 units); CVOW: Coastal Virginia Offshore Wind; Greensville: Greensville County Power Station; MB: Mecklenburg Power Station; Pitt: Pittsylvania Power Station; PP: Possum Point Power Station; SLR: Generic Solar; SLR NUG: Solar NUG; US-3 Solar 1: US-3 Solar 1 Facility; US-3 Solar 2: US-3 Solar 2 Facility;YT: Yorktown Power Station.

Note: 1) Solar NUGs include 660 MW of NC solar NUGs and 100 MW of VA solar NUGs by 2020.

2) These units entered into cold reserve in April 2018.

3) Pittsylvania is planned to enter cold reserve in August 2018.

4) These units are planned to enter cold reserve in December 2018.

	CPP Scenario
NPV Compliance Cost ($B)	$ 0.85

Appendix 2A – Total Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	29,646	28,484	9,779	10,529	282	1,990	80,710
2009	29,904	28,455	8,644	10,448	276	1,932	79,658
2010	32,547	29,233	8,512	10,670	281	1,921	83,164
2011	30,779	28,957	7,960	10,555	273	2,011	80,536
2012	29,174	28,927	7,849	10,496	277	1,984	78,709
2013	30,184	29,372	8,097	10,261	276	1,956	80,145
2014	31,290	29,964	8,812	10,402	261	1,981	82,710
2015	30,923	30,282	8,765	10,159	275	1,856	82,260
2016	28,213	31,366	8,715	10,161	253	1,609	80,318
2017	29,737	32,292	8,638	10,555	258	1,607	83,086
2018	30,245	32,166	8,700	10,443	284	1,601	83,439
2019	30,743	32,714	8,814	10,575	286	1,618	84,750
2020	31,071	33,532	8,757	10,628	288	1,644	85,919
2021	31,305	34,663	8,605	10,777	289	1,659	87,299
2022	31,541	35,861	8,439	10,887	291	1,675	88,694
2023	31,844	36,983	8,289	11,069	293	1,692	90,169
2024	32,291	38,137	8,218	11,201	294	1,715	91,856
2025	32,539	39,131	8,192	11,234	296	1,727	93,120
2026	32,874	40,194	8,201	11,367	297	1,745	94,678
2027	33,211	41,190	8,213	11,470	299	1,764	96,146
2028	33,695	42,200	8,245	11,615	300	1,791	97,846
2029	34,007	42,920	8,211	11,789	302	1,811	99,040
2030	34,399	43,653	8,204	11,965	303	1,835	100,358
2031	35,032	44,410	8,190	11,936	304	1,857	101,728
2032	35,363	45,409	8,263	12,184	305	1,880	103,406
2033	35,649	45,967	8,269	12,175	307	1,903	104,270

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2B– Virginia Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	28,100	27,679	8,064	10,391	273	1,901	76,408
2009	28,325	27,646	7,147	10,312	268	1,883	75,581
2010	30,831	28,408	6,872	10,529	273	1,870	78,784
2011	29,153	28,163	6,342	10,423	265	1,958	76,304
2012	27,672	28,063	6,235	10,370	269	1,934	74,544
2013	28,618	28,487	6,393	10,134	267	1,906	75,804
2014	29,645	29,130	6,954	10,272	253	1,930	78,184
2015	29,293	29,432	7,006	10,029	266	1,803	77,829
2016	26,652	30,537	6,947	10,033	245	1,556	75,971
2017	28,194	31,471	6,893	10,429	250	1,555	78,792
2018	28,609	31,312	6,937	10,316	276	1,548	78,998
2019	29,098	31,856	7,052	10,448	278	1,563	80,296
2020	29,415	32,669	6,995	10,503	280	1,589	81,451
2021	29,640	33,796	6,844	10,652	281	1,604	82,817
2022	29,866	34,989	6,678	10,764	283	1,619	84,199
2023	30,159	36,106	6,528	10,946	284	1,635	85,659
2024	30,568	37,174	6,534	11,070	286	1,658	87,290
2025	30,803	38,143	6,514	11,104	287	1,669	88,520
2026	31,120	39,179	6,521	11,235	289	1,686	90,029
2027	31,439	40,149	6,530	11,337	290	1,705	91,450
2028	31,897	41,135	6,555	11,480	291	1,731	93,089
2029	32,193	41,836	6,528	11,652	293	1,750	94,252
2030	32,564	42,550	6,523	11,826	294	1,773	95,530
2031	33,162	43,288	6,512	11,797	295	1,794	96,849
2032	33,476	44,262	6,570	12,043	297	1,817	98,465
2033	33,747	44,806	6,575	12,033	298	1,839	99,298

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2C – North Carolina Sales by Customer Class (DOM LSE) (GWh)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	1,546	806	1,715	138	8	88	4,302
2009	1,579	809	1,497	136	8	49	4,078
2010	1,716	825	1,640	141	8	51	4,380
2011	1,626	795	1,618	132	8	53	4,232
2012	1,502	864	1,614	126	8	50	4,165
2013	1,567	885	1,704	127	8	50	4,341
2014	1,645	834	1,858	130	8	51	4,526
2015	1,630	850	1,759	130	8	53	4,430
2016	1,562	829	1,768	128	8	53	4,347
2017	1,542	821	1,744	126	8	52	4,293
2018	1,635	854	1,763	127	8	54	4,441
2019	1,645	858	1,762	126	8	54	4,454
2020	1,655	863	1,762	125	8	55	4,468
2021	1,665	867	1,761	124	8	55	4,482
2022	1,676	872	1,761	123	8	56	4,496
2023	1,686	877	1,760	122	8	57	4,510
2024	1,723	963	1,684	130	9	57	4,566
2025	1,736	988	1,679	131	9	58	4,600
2026	1,754	1,015	1,680	132	9	58	4,649
2027	1,772	1,040	1,683	133	9	59	4,696
2028	1,798	1,066	1,689	135	9	60	4,757
2029	1,814	1,084	1,682	137	9	61	4,787
2030	1,835	1,102	1,681	139	9	61	4,828
2031	1,869	1,122	1,678	139	9	62	4,879
2032	1,887	1,147	1,693	142	9	63	4,940
2033	1,902	1,161	1,694	142	9	64	4,972

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2D – Total Customer Count
(DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	2,124,089	230,715	598	29,008	2,513	5	2,386,927
2009	2,139,604	232,148	581	29,073	2,687	5	2,404,099
2010	2,157,581	232,988	561	29,041	2,798	5	2,422,974
2011	2,171,795	233,760	535	29,104	3,031	4	2,438,228
2012	2,187,670	234,947	514	29,114	3,246	3	2,455,495
2013	2,206,657	236,596	526	28,847	3,508	3	2,476,138
2014	2,229,639	237,757	631	28,818	3,653	3	2,500,500
2015	2,252,438	239,623	662	28,923	3,814	3	2,525,463
2016	2,275,551	240,804	654	29,069	3,941	3	2,550,022
2017	2,298,894	242,091	648	28,897	4,149	3	2,574,683
2018	2,328,926	244,229	645	28,874	4,334	3	2,607,011
2019	2,359,240	246,742	644	28,999	4,478	3	2,640,106
2020	2,387,645	249,140	643	29,111	4,622	3	2,671,165
2021	2,414,477	251,434	642	29,206	4,766	3	2,700,528
2022	2,441,710	253,749	641	29,288	4,910	3	2,730,301
2023	2,469,705	256,114	640	29,366	5,054	3	2,760,882
2024	2,497,455	258,466	639	29,438	5,198	3	2,791,198
2025	2,524,076	260,749	638	29,501	5,342	3	2,820,310
2026	2,549,318	262,946	637	29,556	5,486	3	2,847,947
2027	2,573,458	265,074	636	29,603	5,630	3	2,874,405
2028	2,596,881	267,155	635	29,644	5,774	3	2,900,093
2029	2,619,731	269,201	634	29,680	5,918	3	2,925,167
2030	2,642,166	271,220	633	29,711	6,062	3	2,949,795
2031	2,664,350	273,224	632	29,738	6,206	3	2,974,153
2032	2,686,064	275,199	631	29,763	6,350	3	2,998,010
2033	2,708,306	277,201	630	29,781	6,494	3	3,022,415

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2E – Virginia Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	2,023,592	215,212	538	27,141	2,116	3	2,268,602
2009	2,038,843	216,663	522	27,206	2,290	3	2,285,526
2010	2,056,576	217,531	504	27,185	2,404	3	2,304,203
2011	2,070,786	218,341	482	27,252	2,639	2	2,319,502
2012	2,086,647	219,447	464	27,265	2,856	2	2,336,680
2013	2,105,500	221,039	477	26,996	3,118	2	2,357,131
2014	2,128,313	222,143	579	26,966	3,267	2	2,381,269
2015	2,150,818	223,946	611	27,070	3,430	2	2,405,877
2016	2,173,472	225,029	603	27,223	3,560	2	2,429,889
2017	2,196,466	226,270	596	27,041	3,768	2	2,454,143
2018	2,226,232	228,562	585	27,012	3,940	2	2,486,332
2019	2,256,190	231,039	584	27,140	4,083	2	2,519,037
2020	2,284,260	233,402	583	27,256	4,226	2	2,549,730
2021	2,310,777	235,663	582	27,353	4,369	2	2,578,747
2022	2,337,689	237,945	581	27,439	4,512	2	2,608,168
2023	2,365,355	240,275	580	27,518	4,656	2	2,638,386
2024	2,392,778	242,594	579	27,592	4,799	2	2,668,344
2025	2,419,086	244,844	578	27,658	4,942	2	2,697,111
2026	2,444,031	247,009	577	27,715	5,085	2	2,724,420
2027	2,467,888	249,106	576	27,763	5,229	2	2,750,564
2028	2,491,035	251,158	575	27,805	5,372	2	2,775,947
2029	2,513,616	253,174	575	27,842	5,515	2	2,800,723
2030	2,535,787	255,164	574	27,873	5,658	2	2,825,059
2031	2,557,710	257,139	573	27,902	5,801	2	2,849,127
2032	2,579,168	259,086	572	27,927	5,945	2	2,872,700
2033	2,601,149	261,059	571	27,946	6,088	2	2,896,814

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2F – North Carolina Customer Count (DOM LSE)

Year	Residential	Commercial	Industrial	Public Authority	Street and Traffic Lighting	Sales for Resale	Total
2008	100,497	15,502	60	1,867	397	2	118,325
2009	100,761	15,485	59	1,867	398	2	118,573
2010	101,005	15,457	56	1,857	395	2	118,772
2011	101,009	15,418	53	1,852	392	2	118,726
2012	101,024	15,501	50	1,849	390	1	118,815
2013	101,158	15,557	50	1,851	390	1	119,007
2014	101,326	15,614	52	1,853	386	1	119,231
2015	101,620	15,677	52	1,853	384	1	119,586
2016	102,079	15,775	51	1,846	381	1	120,133
2017	102,429	15,821	52	1,857	381	1	120,541
2018	102,694	15,667	60	1,862	394	1	120,679
2019	103,050	15,704	60	1,858	395	1	121,069
2020	103,385	15,738	60	1,855	396	1	121,435
2021	103,700	15,771	60	1,852	397	1	121,782
2022	104,021	15,804	60	1,850	398	1	122,134
2023	104,350	15,839	60	1,847	398	1	122,495
2024	104,676	15,872	60	1,845	399	1	122,854
2025	104,990	15,905	60	1,843	400	1	123,199
2026	105,287	15,937	60	1,842	401	1	123,527
2027	105,571	15,968	60	1,840	401	1	123,841
2028	105,846	15,998	60	1,839	402	1	124,146
2029	106,115	16,027	60	1,838	403	1	124,444
2030	106,379	16,056	60	1,837	404	1	124,737
2031	106,640	16,085	60	1,836	405	1	125,026
2032	106,895	16,113	60	1,835	405	1	125,310
2033	107,157	16,142	60	1,835	406	1	125,601

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2G – Zonal Summer and Winter Peak Demand (MW)

Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)
2008	19,051	17,028
2009	18,137	17,904
2010	19,140	17,689
2011	20,061	17,889
2012	19,249	16,881
2013	18,763	17,623
2014	18,692	19,784
2015	18,980	21,651
2016	19,538	18,948
2017	18,902	19,661
2018	19,938	18,666
2019	20,282	18,974
2020	20,568	19,291
2021	20,867	19,748
2022	21,161	20,191
2023	21,477	20,517
2024	22,010	20,862
2025	22,381	21,175
2026	22,757	21,534
2027	23,006	22,024
2028	23,228	22,394
2029	23,567	22,537
2030	23,960	22,696
2031	24,230	22,935
2032	24,422	23,161
2033	24,610	23,608

Note: Historic (2008 – 2017), Projected (2018 – 2033).

Appendix 2H – Summer & Winter Peaks for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 5**

POWER SUPPLY DATA

	(ACTUAL)				(PROJECTED)														
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
II. Load (MW)																			
1. Summer																			
a. Adjusted Summer Peak[1]	16,461	16,821	16,241	17,413	17,674	17,766	18,026	18,284	18,559	19,025	19,351	19,682	19,899	20,093	20,389	20,733	20,967	21,133	21,297
b. Other Commitments[2]	72	93	109	4	43	202	203	202	204	202	200	198	198	198	198	198	200	201	202
c. Total System Summer Peak	16,533	16,914	16,350	17,417	17,718	17,968	18,229	18,486	18,762	19,227	19,551	19,880	20,097	20,292	20,587	20,931	21,167	21,334	21,499
d. Percent Increase in Total Summer Peak	1.7%	2.3%	-3.3%	6.5%	1.7%	1.4%	1.5%	1.4%	1.5%	2.5%	1.7%	1.7%	1.1%	1.0%	1.5%	1.7%	1.1%	0.8%	0.8%
2. Winter																			
a. Adjusted Winter Peak[1]	18,616	16,080	16,509	16,038	16,261	16,380	16,772	17,160	17,439	17,736	18,009	18,320	18,743	19,061	19,185	19,322	19,527	19,721	20,104
b. Other Commitments[2]	72	93	109	-18.5	22	176	175	167	168	168	164	160	157	157	156	155	155	155	156
c. Total System Winter Peak	18,688	16,173	16,618	16,019	16,283	16,555	16,947	17,328	17,607	17,904	18,172	18,480	18,901	19,218	19,341	19,477	19,682	19,876	20,260
d. Percent Increase in Total Winter Peak	11.0%	-13.5%	2.8%	-3.6%	1.6%	1.7%	2.4%	2.2%	1.6%	1.7%	1.5%	1.7%	2.3%	1.7%	0.6%	0.7%	1.1%	1.0%	1.9%

(1) Adjusted load from Appendix 2I.

(2) Includes firm Additional Forecast, Conservation Efficiency, and Peak Adjustments from Appendix 2I.

Appendix 2I – Projected Summer & Winter Peak Load & Energy Forecast for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)(1)				(PROJECTED)														
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,530	16,914	16,350	17,417	17,718	17,968	18,229	18,486	18,762	19,227	19,551	19,880	20,097	20,292	20,587	20,931	21,167	21,334	21,499
1b. Additional Forecast																			
NCEMC	0	-	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency(5)	-72	-93	-109	-154	-193	-202	-203	-202	-204	-202	-200	-198	-198	-198	-198	-198	-200	-201	-202
3. Demand Response(2)(5)	-81	-103	-70	-99	-100	-100	-101	-101	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102
4. Demand Response-Existing(2)(3)	-2	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
5. Peak Adjustment	-	-	-																
6. Adjusted Load	16,461	16,821	16,241	17,413	17,674	17,766	18,026	18,284	18,559	19,025	19,351	19,682	19,899	20,093	20,389	20,733	20,967	21,133	21,297
7. % Increase in Adjusted Load	0.7%	2.2%	-3.4%	7.2%	1.5%	0.5%	1.5%	1.4%	1.5%	2.5%	1.7%	1.7%	1.1%	1.0%	1.5%	1.7%	1.1%	0.8%	0.8%
(from previous year)																			
B. Winter																			
1a. Base Forecast	18,688	16,173	16,618	16,019	16,283	16,555	16,947	17,328	17,607	17,904	18,172	18,480	18,901	19,218	19,341	19,477	19,682	19,876	20,260
1b. Additional Forecast																			
NCEMC	0	-	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency(5)	-72	-93	-109	-131.5	-172.2	-175.6	-175.2	-167.3	-168.2	-167.8	-163.5	-160.3	-157.4	-157.0	-156.0	-155.3	-154.7	-155.0	-155.6
3. Demand Response(2)(4)	-5	-4	-5	-8	-8	-9	-9	-10	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11
4. Demand Response-Existing(2)(3)	-2	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
5. Adjusted Load	18,616	16,080	16,509	16,038	16,261	16,380	16,772	17,160	17,439	17,736	18,009	18,320	18,743	19,061	19,185	19,322	19,527	19,721	20,104
6. % Increase in Adjusted Load	9.9%	-13.6%	2.7%	-2.9%	1.4%	0.7%	2.4%	2.3%	1.6%	1.7%	1.5%	1.7%	2.3%	1.7%	0.7%	0.7%	1.1%	1.0%	1.9%
2. Energy (GWh)																			
A. Base Forecast	84,755	84,698	84,046	89,276	90,579	90,738	92,101	93,611	95,144	96,951	98,329	99,935	101,448	103,185	104,300	105,538	106,851	108,421	109,248
B. Additional Forecast																			
Future BTM(6)	-	-	-	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416	-416
C. Conservation & Demand Response(5)	-460	-556	-660	-805	-930	-933	-882	-840	-836	-826	-811	-801	-795	-795	-795	-795	-798	-801	-805
D. Demand Response-Existing(2)(3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E. Adjusted Energy	84,295	84,142	83,386	88,056	89,233	89,390	90,803	92,355	93,892	95,709	97,102	98,718	100,237	101,974	103,089	104,326	105,637	107,203	108,027
F. % Increase in Adjusted Energy	0.5%	-0.2%	-0.9%	5.6%	1.3%	0.2%	1.6%	1.7%	1.7%	1.9%	1.5%	1.7%	1.5%	1.7%	1.1%	1.2%	1.3%	1.5%	0.8%

(1) Actual metered data.
(2) Demand response programs are classified as capacity resources and are not included in adjusted load.
(3) Existing DSM programs are included in the load forecast.
(4) Actual historical data based upon measured and verified EM&V results.
(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.
(6) Future BTMG, which is not included in the Base forecast.

Appendix 2J – Required Reserve Margin for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 6**

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
I. Reserve Margin[(1)]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[(1)]	3,742	3,919	3,506	1,356	2,622	2,595	2,190	2,191	2,283	2,264	2,304	2,339	2,429	2,443	2,495	2,481	2,522	2,563	2,507
b. Percent of Load	22.7%	23.2%	21.4%	7.8%	14.8%	14.6%	12.2%	12.0%	12.3%	11.9%	11.9%	11.9%	12.2%	12.2%	12.2%	12.0%	12.0%	12.1%	11.8%
c. Actual Reserve Margin[(3)]	N/A	N/A	N/A	6.9%	13.7%	13.5%	7.7%	3.8%	5.3%	5.6%	6.7%	7.8%	7.2%	6.7%	7.8%	8.6%	9.6%	9.3%	8.9%
2. Winter Reserve Margin																			
a. MW[(1)]	N/A	N/A	N/A	4,430	4,745	4,750	4,374	4,405	4,528	4,572	4,649	4,724	4,838	4,872	4,961	4,991	5,059	5,117	5,078
b. Percent of Load	N/A	N/A	N/A	27.6%	29.2%	29.0%	26.1%	25.7%	26.0%	25.8%	25.8%	25.8%	25.8%	25.6%	25.9%	25.8%	25.9%	25.9%	25.3%
c. Actual Reserve Margin[(3)]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin[(1)(2)]																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[(1)]	3,742	3,919	3,506	1,356	2,622	2,595	2,190	2,191	2,283	2,264	2,304	2,339	2,429	2,443	2,495	2,481	2,522	2,563	2,507
b. Percent of Load	22.7%	23.2%	21.4%	7.8%	14.8%	14.6%	12.2%	12.0%	12.3%	11.9%	11.9%	11.9%	12.2%	12.2%	12.2%	12.0%	12.0%	12.1%	11.8%
c. Actual Reserve Margin[(3)]	N/A	N/A	N/A	6.9%	13.7%	13.5%	7.7%	3.8%	5.3%	5.6%	6.7%	7.8%	7.2%	6.7%	7.8%	8.6%	9.6%	9.3%	8.9%
2. Winter Reserve Margin																			
a. MW[(1)]	N/A	N/A	N/A	4,430	4,745	4,750	4,374	4,405	4,528	4,572	4,649	4,724	4,838	4,872	4,961	4,991	5,059	5,117	5,078
b. Percent of Load	N/A	N/A	N/A	27.6%	29.2%	29.0%	26.1%	25.7%	26.0%	25.8%	25.8%	25.8%	25.8%	25.6%	25.9%	25.8%	25.9%	25.9%	25.3%
c. Actual Reserve Margin[(3)]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours[(4)]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.
(2) The Company and PJM forecast a summer peak throughout the Planning Period.
(3) Does not include spot purchases of capacity.
(4) The Company follows PJM reserve requirements which are based on LOLE.

Appendix 2K – Economic Assumptions used In the Sales and Hourly Budget Forecast Model (Annual Growth Rate)

	Economic Assumptions Used In the Sales and Hourly Budget Forecast Model (Annual Growth Rate)																
Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	CAGR
Population: Total, (Ths.)	8,515	8,573	8,634	8,696	8,759	8,823	8,888	8,952	9,014	9,075	9,135	9,194	9,252	9,309	9,365	9,419	0.7%
Disposable Personal Income; (Mil. 09$; SAAR)	363,555	369,194	371,690	378,132	387,173	396,157	404,592	413,849	424,004	435,123	447,424	459,841	472,332	485,246	498,065	510,946	2.3%
Per Capita Disposable Personal Income; (C 09$; SAAR)	42.7	43.1	43.1	43.5	44.2	44.9	45.5	46.2	47.0	48.0	49.0	50.0	51.1	52.1	53.2	54.3	1.6%
Residential Permits: Total, (#, SAAR)	33,671	38,269	41,608	42,926	42,490	41,125	40,044	40,088	39,574	37,906	36,837	36,021	35,410	34,978	34,459	33,850	0.0%
Employment: Total Manufacturing, (Ths., SA)	233	231	226	223	222	219	216	213	211	208	206	203	201	199	197	195	-1.2%
Employment: Total Government, (Ths., SA)	718.8	723.0	726.4	732.2	738.8	745.1	750.4	755.6	760.9	766.4	772.1	778.0	783.9	789.5	793.9	798.0	0.7%
Employment: Military personnel, (Ths., SA)	140	138	136	134	134	133	133	132	132	131	131	131	130	130	129	129	-0.6%
Employment: State and local government, (Ths., SA)	540	544	547	552	559	565	570	575	580	585	591	597	602	607	612	615	0.9%
Employment: Commercial Sector (Ths., SA)	2,878.8	2,907.4	2,909.2	2,932.1	2,969.3	3,003.3	3,025.2	3,044.4	3,064.9	3,084.2	3,106.5	3,127.7	3,147.6	3,168.7	3,190.5	3,213.8	0.7%
Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR)	38,731	39,439	39,564	40,605	41,365	41,785	42,108	42,589	43,153	43,705	44,363	44,984	45,547	46,146	46,751	47,379	1.4%
Gross State Product: Total; (Bil. Chained 2009 $; SAAR)	460.8	471.0	476.2	488.6	500.5	510.6	519.8	529.9	540.6	551.2	562.9	574.3	585.4	596.6	608.0	619.6	2.0%
Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR)	36,483	36,681	36,843	37,446	38,096	38,766	39,329	39,871	40,433	41,002	41,564	42,072	42,553	43,026	43,501	43,978	1.25%

Source: Economy.com October 2017 vintage

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	CAGR
Population: Total, (Ths.)	8,509	8,574	8,640	8,706	8,772	8,836	8,900	8,964	9,027	9,089	9,150	9,210	9,269	9,327	9,384	9,439	0.7%
Disposable Personal Income; (Mil. 09$; SAAR)	365,950	377,278	387,490	394,384	401,240	409,165	417,599	426,195	435,536	445,512	456,403	467,756	479,593	491,709	504,174	516,539	2.3%
Per Capita Disposable Personal Income; (C 09$; SAAR)	43.0	44.0	44.9	45.3	45.8	46.3	46.9	47.6	48.3	49.0	49.9	50.8	51.8	52.7	53.7	54.7	1.6%
Residential Permits: Total, (#, SAAR)	42,506	48,313	45,191	40,717	40,897	42,895	43,159	41,366	38,737	36,428	35,057	34,060	33,036	32,699	32,105	30,863	-2.1%
Employment: Total Manufacturing, (Ths., SA)	228	227	226	223	220	216	214	211	208	206	204	202	200	198	196	195	-1.1%
Employment: Total Government, (Ths., SA)	718.7	721.4	724.9	729.1	734.3	740.3	745.8	750.8	755.9	761.3	766.7	772.3	778.1	783.8	789.2	793.4	0.7%
Employment: Military personnel, (Ths., SA)	135	133	131	129	128	127	127	126	126	125	125	124	124	124	123	123	-0.6%
Employment: State and local government, (Ths., SA)	539	542	545	549	554	560	565	570	575	580	586	591	596	602	607	611	0.8%
Employment: Commercial Sector (Ths., SA)	2,844.4	2,895.8	2,946.0	2,970.3	2,983.4	3,003.2	3,029.1	3,053.0	3,077.3	3,102.5	3,127.5	3,152.7	3,179.0	3,206.0	3,234.0	3,263.5	0.9%
Gross State Product: Total Manufacturing; (Bil. Chained 2009 $; SAAR)	39,054	39,979	40,547	40,828	41,230	41,727	42,317	42,896	43,490	44,138	44,831	45,550	46,269	46,973	47,674	48,352	1.4%
Gross State Product: Total; (Bil. Chained 2009 $; SAAR)	459.0	473.2	483.8	491.2	500.1	510.5	521.3	531.6	542.1	553.2	564.6	575.9	587.3	598.7	610.1	621.5	2.0%
Gross State Product: Local Government; (Bil. Chained 2009 $; SAAR)	35,094	35,409	35,616	35,798	36,188	36,640	37,058	37,452	37,852	38,256	38,638	38,979	39,307	39,623	39,929	40,247	0.92%

Source: Economy.com October 2016 vintage

Appendix 3A – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.(1)	MW Summer	MW Winter
Altavista	Altavista, VA	Base	Renewable	Feb-1992	51	51
Bath County 1-6	Warm Springs, VA	Intermediate	Hydro-Pumped Storage	Dec-1985	1,808	1,808
Bear Garden	Buckingham County, VA	Intermediate	Natural Gas-CC	May-2011	622	654
Bellemeade	Richmond, VA	Intermediate	Natural Gas-CC	Mar-1991	0	0
Bremo 3	Bremo Bluff, VA	Peak	Natural Gas	Jun-1950	0	0
Bremo 4	Bremo Bluff, VA	Peak	Natural Gas	Aug-1958	0	0
Brunswick	Brunswick County, VA	Intermediate	Natural Gas-CC	May-2016	1,376	1,470
Chesapeake CT 1, 2, 4, 6	Chesapeake, VA	Peak	Light Fuel Oil	Dec-1967	51	69
Chesterfield 3	Chester, VA	Base	Coal	Dec-1952	0	0
Chesterfield 4	Chester, VA	Base	Coal	Jun-1960	0	0
Chesterfield 5	Chester, VA	Base	Coal	Aug-1964	336	342
Chesterfield 6	Chester, VA	Base	Coal	Dec-1969	670	690
Chesterfield 7	Chester, VA	Intermediate	Natural Gas-CC	Jun-1990	197	226
Chesterfield 8	Chester, VA	Intermediate	Natural Gas-CC	May-1992	200	236
Clover 1	Clover, VA	Base	Coal	Oct-1995	220	222
Clover 2	Clover, VA	Base	Coal	Mar-1996	219	219
Darbytown 1	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	98
Darbytown 2	Richmond, VA	Peak	Natural Gas-Turbine	May-1990	84	97
Darbytown 3	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	95
Darbytown 4	Richmond, VA	Peak	Natural Gas-Turbine	Apr-1990	84	97
Elizabeth River 1	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	121
Elizabeth River 2	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	120
Elizabeth River 3	Chesapeake, VA	Peak	Natural Gas-Turbine	Jun-1992	116	124
Gaston Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Feb-1963	220	220
Gordonsville 1	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	139
Gordonsville 2	Gordonsville, VA	Intermediate	Natural Gas-CC	Jun-1994	109	139
Gravel Neck 1-2	Surry, VA	Peak	Light Fuel Oil	Aug-1970	28	38
Gravel Neck 3	Surry, VA	Peak	Natural Gas-Turbine	Oct-1989	85	98
Gravel Neck 4	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	97
Gravel Neck 5	Surry, VA	Peak	Natural Gas-Turbine	Jul-1989	85	98
Gravel Neck 6	Surry, VA	Peak	Natural Gas-Turbine	Nov-1989	85	97
Hopewell	Hopewell, VA	Base	Renewable	Jul-1989	51	51
Ladysmith 1	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 2	Woodford, VA	Peak	Natural Gas-Turbine	May-2001	151	183
Ladysmith 3	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	161	183
Ladysmith 4	Woodford, VA	Peak	Natural Gas-Turbine	Jun-2008	160	183
Ladysmith 5	Woodford, VA	Peak	Natural Gas-Turbine	Apr-2009	160	183
Lowmoor CT 1-4	Covington, VA	Peak	Light Fuel Oil	Jul-1971	48	65
Mecklenburg 1	Clarksville, VA	Base	Coal	Nov-1992	0	0
Mecklenburg 2	Clarksville, VA	Base	Coal	Nov-1992	0	0

(1) Commercial Operation Date

Appendix 3A cont. – Existing Generation Units in Service

Company Name: Virginia Electric and Power Company **Schedule 14a**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (MW)

Unit Name	Location	Unit Class	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Winter
Mount Storm 1	Mt. Storm, WV	Base	Coal	Sep-1965	554	569
Mount Storm 2	Mt. Storm, WV	Base	Coal	Jul-1966	555	570
Mount Storm 3	Mt. Storm, WV	Base	Coal	Dec-1973	520	537
Mount Storm CT	Mt. Storm, WV	Peak	Light Fuel Oil	Oct-1967	11	15
North Anna 1	Mineral, VA	Base	Nuclear	Jun-1978	838	868
North Anna 2	Mineral, VA	Base	Nuclear	Dec-1980	834	863
North Anna Hydro	Mineral, VA	Intermediate	Hydro-Conventional	Dec-1987	1	1
Northern Neck CT 1-4	Warsaw, VA	Peak	Light Fuel Oil	Jul-1971	47	70
Pittsylvania	Hurt, VA	Base	Renewable	Jun-1994	0	0
Possum Point 3	Dumfries, VA	Peak	Natural Gas	Jun-1955	0	0
Possum Point 4	Dumfries, VA	Peak	Natural Gas	Apr-1962	0	0
Possum Point 5	Dumfries, VA	Peak	Heavy Fuel Oil	Jun-1975	786	805
Possum Point 6	Dumfries, VA	Intermediate	Natural Gas-CC	Jul-2003	573	615
Possum Point CT 1-6	Dumfries, VA	Peak	Light Fuel Oil	May-1968	72	106
Remington 1	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	153	187
Remington 2	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	151	187
Remington 3	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	187
Remington 4	Remington, VA	Peak	Natural Gas-Turbine	Jul-2000	152	188
Roanoke Rapids Hydro	Roanoake Rapids, NC	Intermediate	Hydro-Conventional	Sep-1955	95	95
Rosemary	Roanoke Rapids, NC	Peak	Natural Gas-CC	Dec-1990	165	165
Scott Solar	Powhatan, VA	Intermittent	Renewable	Dec-2016	4	17
Solar Partnership Program	Distributed	Intermittent	Renewable	Jan-2012	2	7
Southampton	Franklin, VA	Base	Renewable	Mar-1992	51	51
Surry 1	Surry, VA	Base	Nuclear	Dec-1972	838	875
Surry 2	Surry, VA	Base	Nuclear	May-1973	838	875
Virginia City Hybrid Energy Center	Virginia City, VA	Base	Coal	Jul-2012	610	624
Warren	Front Royal, VA	Intermediate	Natural Gas-CC	Dec-2014	1,342	1,436
Whitehouse Solar	Louisa, VA	Intermittent	Renewable	Dec-2016	5	20
Woodland Solar	Isle of Wight, VA	Intermittent	Renewable	Dec-2016	4	19
Yorktown 1	Yorktown, VA	Base	Coal	Jul-1957	0	0
Yorktown 2	Yorktown, VA	Base	Coal	Jan-1959	0	0
Yorktown 3	Yorktown, VA	Peak	Heavy Fuel Oil	Dec-1974	790	792
Subtotal - Base					7,185	7,406
Subtotal - Intermediate					6,652	7,039
Subtotal - Peak					4,413	4,931
Subtotal - Intermittent					15	63
Total					18,265	19,440

Note: Summer MW for solar generation represents firm capacity.

(1) Commercial Operation Date.

Appendix 3B – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Non-Utility Generation (NUG) Units[1]							
SEI Birchwood	King George, VA	Base	Coal	217,800	Yes	11/15/1996	11/14/2021
Behind-The-Meter (BTM) Generation Units							
Alexandria/Arlington - Covanta	VA	NUG	MSW	21,000	No	1/29/1988	1/28/2023
Brasfield Dam	VA	Must Take	Hydro	2,500	No	10/12/1993	Auto renew
Suffolk Landfill	VA	Must Take	Methane	3,000	No	11/4/1994	Auto renew
Columbia Mills	VA	Must Take	Hydro	343	No	2/7/1985	Auto renew
Lakeview (Swift Creek) Dam	VA	Must Take	Hydro	400	No	11/26/2008	Auto renew
MeadWestvaco (formerly Westvaco)	VA	NUG	Coal/Biomass	140,000	No	11/3/1982	9/30/2028
Banister Dam	VA	Must Take	Hydro	1,785	No	9/28/2008	Auto renew
Jockey's Ridge State Park	NC	Must Take	Wind	10	No	5/21/2010	Auto renew
302 First Flight Run	NC	Must Take	Solar	3	No	5/5/2010	Auto renew
3620 Virginia Dare Trail N	NC	Must Take	Solar	4	No	9/14/2009	Auto renew
Weyerhaeuser/Domtar	NC	NUG	Coal/biomass	28,400[2]	No	7/27/1991	Auto renew
Chapman Dam	VA	Must Take	Hydro	300	No	10/17/1984	Auto renew
Smurfit-Stone Container	VA	NUG	Coal/biomass	48,400[3]	No	3/21/1981	Auto renew
Rivanna	VA	Must Take	Hydro	100	No	4/21/1998	Auto renew
Rapidan Mill	VA	Must Take	Hydro	100	No	6/15/2009	Auto renew
Burnshire Dam	VA	Must Take	Hydro	100	No	7/11/2016	Auto renew
Dairy Energy	VA	Must Take	Biomass	400	No	8/2/2011	7/31/2019
Essex Solar Center	VA	Must Take	Solar	20,000	No	12/14/2017	12/13/2037
W. E. Partners II	NC	Must Take	Biomass	300	No	3/15/2012	Auto renew
Plymouth Solar	NC	Must Take	Solar	5,000	No	10/4/2012	10/3/2027
W. E. Partners 1	NC	Must Take	Biomass	100	No	4/26/2013	Auto renew
Dogwood Solar	NC	Must Take	Solar	20,000	No	12/9/2014	12/8/2029
HXOap Solar	NC	Must Take	Solar	20,000	No	12/16/2014	12/15/2029
Bethel Price Solar	NC	Must Take	Solar	5,000	No	12/9/2014	12/8/2029
Jakana Solar	NC	Must Take	Solar	5,000	No	12/4/2014	12/3/2029
Lewiston Solar	NC	Must Take	Solar	5,000	No	12/18/2014	12/17/2029
Williamston Solar	NC	Must Take	Solar	5,000	No	12/4/2014	12/3/2029
Windsor Solar	NC	Must Take	Solar	5,000	No	12/17/2014	12/16/2029
510 REPP One Solar	NC	Must Take	Solar	1,250	No	3/11/2015	3/10/2030
Everetts Wildcat Solar	NC	Must Take	Solar	5,000	No	3/11/2015	3/10/2030
SolNC5 Solar	NC	Must Take	Solar	5,000	No	5/12/2015	5/11/2030
Creswell Aligood Solar	NC	Must Take	Solar	14,000	No	5/13/2015	5/12/2030
Two Mile Desert Road - SolNC1	NC	Must Take	Solar	5,000	No	8/10/2015	8/9/2030
SolNCPower6 Solar	NC	Must Take	Solar	5,000	No	11/1/2015	10/31/2030
Downs Farm Solar	NC	Must Take	Solar	5,000	No	12/1/2015	11/30/2030
GKS Solar- SolNC2	NC	Must Take	Solar	5,000	No	12/16/2015	12/15/2030
Windsor Cooper Hill Solar	NC	Must Take	Solar	5,000	No	12/18/2015	12/17/2030
Green Farm Solar	NC	Must Take	Solar	5,000	No	1/6/2016	1/5/2031
FAE X - Shawboro	NC	Must Take	Solar	20,000	No	1/26/2016	1/25/2031
FAE XVII - Watson Seed	NC	Must Take	Solar	20,000	No	1/28/2016	1/27/2031
Bradley PVI- FAE IX	NC	Must Take	Solar	5,000	No	2/4/2016	2/3/2031
Conetoe Solar	NC	Must Take	Solar	5,000	No	2/5/2016	2/4/2031
SolNC3 Solar-Sugar Run Solar	NC	Must Take	Solar	5,000	No	2/5/2016	2/4/2031
Gates Solar	NC	Must Take	Solar	5,000	No	2/8/2016	2/7/2031
Long Farm 46 Solar	NC	Must Take	Solar	5,000	No	2/12/2016	2/11/2031
Battleboro Farm Solar	NC	Must Take	Solar	5,000	No	2/17/2016	2/16/2031
Winton Solar	NC	Must Take	Solar	5,000	No	2/8/2016	2/7/2031
SolNC10 Solar	NC	Must Take	Solar	5,000	No	1/13/2016	1/12/2031

(1) In operation as of March 1, 2018.
(2) PPA is for excess energy only, typically 4,000 – 14,000 kW.
(3) PPA is for excess energy only, typically 3,500 kW.

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Behind-The-Meter (BTM) Generation Units							
Tarboro Solar	NC	Must Take	Solar	5,000	No	12/31/2015	12/30/2030
Bethel Solar	NC	Must Take	Solar	4,400	No	3/3/2016	3/2/2031
Garysburg Solar	NC	Must Take	Solar	5,000	No	3/18/2016	3/17/2031
Woodland Solar	NC	Must Take	Solar	5,000	No	4/7/2016	4/6/2031
Gaston Solar	NC	Must Take	Solar	5,000	No	4/18/2016	4/17/2031
TWE Kelford Solar	NC	Must Take	Solar	4,700	No	6/6/2016	6/5/2031
FAE XVIII - Meadows	NC	Must Take	Solar	20,000	No	6/9/2016	6/8/2031
Seaboard Solar	NC	Must Take	Solar	5,000	No	6/29/2016	6/28/2031
Simons Farm Solar	NC	Must Take	Solar	5,000	No	7/13/2016	7/12/2031
Whitakers Farm Solar	NC	Must Take	Solar	3,400	No	7/20/2016	7/19/2031
MC1 Solar	NC	Must Take	Solar	5,000	No	8/19/2016	8/18/2031
Williamston West Farm Solar	NC	Must Take	Solar	5,000	No	8/23/2016	8/22/2031
River Road Solar	NC	Must Take	Solar	5,000	No	8/23/2016	8/22/2031
White Farm Solar	NC	Must Take	Solar	5,000	No	8/26/2016	8/25/2031
Hardison Farm Solar	NC	Must Take	Solar	5,000	No	9/9/2016	9/8/2031
Modlin Farm Solar	NC	Must Take	Solar	5,000	No	9/14/2016	9/13/2031
Battleboro Solar	NC	Must Take	Solar	5,000	No	10/7/2016	10/6/2031
Williamston Speight Solar	NC	Must Take	Solar	15,000	No	11/23/2016	11/22/2031
Barnhill Road Solar	NC	Must Take	Solar	3,100	No	11/30/2016	11/29/2031
Hemlock Solar	NC	Must Take	Solar	5,000	No	12/5/2016	12/4/2031
Leggett Solar	NC	Must Take	Solar	5,000	No	12/14/2016	12/13/2031
Schell Solar Farm	NC	Must Take	Solar	5,000	No	12/22/2016	12/21/2031
FAE XXXV - Turkey Creek	NC	Must Take	Solar	13,500	No	1/31/2017	1/30/2027
FAE XXII - Baker PVI	NC	Must Take	Solar	5,000	No	1/30/2017	1/29/2032
FAE XXI -Benthall Bridge PVI	NC	Must Take	Solar	5,000	No	1/30/2017	1/29/2032
Aulander Hwy 42 Solar	NC	Must Take	Solar	5,000	No	12/30/2016	12/29/2031
Floyd Road Solar	NC	Must Take	Solar	5,000	No	6/19/2017	6/18/2032
Flat Meeks- FAE II	NC	Must Take	Solar	5,000	No	10/27/2017	10/26/2032
HXNAir Solar One	NC	Must Take	Solar	5,000	No	12/21/2017	12/20/2032
Cork Oak Solar	NC	Must Take	Solar	20,000	No	12/29/2017	12/28/2032
Sunflower Solar	NC	Must Take	Solar	16,000	No	12/29/2017	12/28/2032
Davis Lane Solar	NC	Must Take	Solar	5,000	No	12/31/2017	12/30/2032
FAE XIX- American Legion PVI	NC	Must Take	Solar	15,840	No	1/2/2018	1/1/2033
FAE XXV-Vaughn's Creek	NC	Must Take	Solar	20,000	No	1/2/2018	1/1/2033
TWE Ahoskie Solar Project	NC	Must Take	Solar	5,000	No	1/12/2018	1/11/2033
Cottonwood Solar	NC	Must Take	Solar	3,000	No	1/25/2018	1/24/2033
Shiloh Hwy 1108 Solar	NC	Must Take	Solar	5,000	No	2/9/2018	2/8/2033
Chowan Jehu Road Solar	NC	Must Take	Solar	5,000	No	2/9/2018	2/8/2033
Phelps 158 Solar Farm	NC	Must Take	Solar	5,000	No	2/26/2018	2/25/2033

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	25000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	Natural Gas	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	VA Beach	Standby	Diesel	3500	No	N/A	N/A
	VA Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/ Natural Gas	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	Natural Gas	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	Natural Gas	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	Natural Gas	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	Natural Gas	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black Liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Natural Gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Northern VA	Standby	Diesel	1270	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Alexandria	Standby	Diesel	300	No	N/A	N/A
	Alexandria	Standby	Diesel	475	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 60	No	N/A	N/A
	Northern VA	Standby	Diesel	14000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Norfolk	Standby	Diesel	4000	No	N/A	N/A
	Richmond	Standby	Diesel	4470	No	N/A	N/A
	Arlington	Standby	Diesel	5650	No	N/A	N/A
	Ashburn	Standby	Diesel	22000	No	N/A	N/A
	Richmond	Standby	Diesel	22950	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Hampton Roads	Standby	Diesel	3000	No	N/A	N/A
	Northern VA	Standby	Diesel	900	No	N/A	N/A
	Richmond	Standby	Diesel	20110	No	N/A	N/A
	Richmond	Standby	Diesel	3500	No	N/A	N/A
	Richmond	Standby	NG	10	No	N/A	N/A
	Richmond	Standby	LP	120	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesapeake	Standby	Diesel	500	No	N/A	N/A
	Chesapeake	Standby	Diesel	2500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	700	No	N/A	N/A
	Hopewell	Standby	Diesel	75	No	N/A	N/A
	Newport News	Standby	Unknown	1000	No	N/A	N/A
	Newport News	Standby	Unknown	4500	No	N/A	N/A
	Norfolk	Standby	Diesel	2000	No	N/A	N/A
	Norfolk	Standby	Diesel	9000	No	N/A	N/A
	Portsmouth	Standby	Diesel	2250	No	N/A	N/A
	Va Beach	Standby	Diesel	3500	No	N/A	N/A
	Va Beach	Standby	Diesel	2000	No	N/A	N/A
	Chesterfield	Standby	Diesel	2000	No	N/A	N/A
	Central VA	Merchant	Coal	92000	No	N/A	N/A
	Central VA	Merchant	Coal	115000	No	N/A	N/A
	Williamsburg	Standby	Diesel	2800	No	N/A	N/A
	Richmond	Standby	Diesel	30000	No	N/A	N/A
	Charlottesville	Standby	Diesel	40000	No	N/A	N/A
	Arlington	Standby	Diesel	13042	No	N/A	N/A
	Arlington	Standby	Diesel/NG	5000	No	N/A	N/A
	Fauquier	Standby	Diesel	1885	No	N/A	N/A
	Hanover	Standby	Diesel	12709.5	No	N/A	N/A
	Hanover	Standby	NG	13759.5	No	N/A	N/A
	Hanover	Standby	LP	81.25	No	N/A	N/A
	Henrico	Standby	NG	1341	No	N/A	N/A
	Henrico	Standby	LP	126	No	N/A	N/A
	Henrico	Standby	Diesel	828	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Newport News	Standby	Diesel	1750	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Chesapeake	Standby	Unknown	750	No	N/A	N/A
	Northern VA	Merchant	NG	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	138000	No	N/A	N/A
	Richmond	Standby	Steam	20000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Herndon	Standby	Diesel	415	No	N/A	N/A
	Herndon	Standby	Diesel	50	No	N/A	N/A
	VA	Merchant	Hydro	2700	No	N/A	N/A
	Northern VA	Standby	Diesel	37000	No	N/A	N/A
	Fairfax County	Standby	Diesel	20205	No	N/A	N/A
	Fairfax County	Standby	NG	2139	No	N/A	N/A
	Fairfax County	Standby	LP	292	No	N/A	N/A
	Springfield	Standby	Diesel	6500	No	N/A	N/A
	Warrenton	Standby	Diesel	2 - 750	No	N/A	N/A
	Northern VA	Standby	Diesel	5350	No	N/A	N/A
	Richmond	Standby	Diesel	16400	No	N/A	N/A
	Norfolk	Standby	Diesel	350	No	N/A	N/A
	Charlottesville	Standby	Diesel	400	No	N/A	N/A
	Farmville	Standby	Diesel	350	No	N/A	N/A
	Mechanicsville	Standby	Diesel	350	No	N/A	N/A
	King George	Standby	Diesel	350	No	N/A	N/A
	Chatham	Standby	Diesel	350	No	N/A	N/A
	Hampton	Standby	Diesel	350	No	N/A	N/A
	Virginia Beach	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	400	No	N/A	N/A
	Powhatan	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Richmond	Standby	Diesel	350	No	N/A	N/A
	Chesapeake	Standby	Diesel	400	No	N/A	N/A
	Newport News	Standby	Diesel	350	No	N/A	N/A
	Dinwiddie	Standby	Diesel	300	No	N/A	N/A
	Goochland	Standby	Diesel	350	No	N/A	N/A
	Portsmouth	Standby	Diesel	350	No	N/A	N/A
	Fredericksburg	Standby	Diesel	350	No	N/A	N/A
	Northern VA	Standby	Diesel	22690	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	15100	No	N/A	N/A
	Herndon	Standby	Diesel	1250	No	N/A	N/A
	Herndon	Standby	Diesel	500	No	N/A	N/A
	Henrico	Standby	Diesel	1000	No	N/A	N/A
	Alexandria	Standby	Diesel	2 - 910	No	N/A	N/A
	Alexandria	Standby	Diesel	1000	No	N/A	N/A
	Fairfax	Standby	Diesel	4 - 750	No	N/A	N/A
	Loudoun	Standby	Diesel	2100	No	N/A	N/A
	Loudoun	Standby	Diesel	710	No	N/A	N/A
	Mount Vernon	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Eastern VA	Standby	Black liquor/Natural Gas	112500	No	N/A	N/A
	Central VA	Standby	Diesel	1700	No	N/A	N/A
	Hopewell	Standby	Diesel	500	No	N/A	N/A
	Falls Church	Standby	Diesel	200	No	N/A	N/A
	Falls Church	Standby	Diesel	250	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned(3)							
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Fredericksburg	Standby	Diesel	4200	No	N/A	N/A
	Norfolk	Standby	NG	1050	No	N/A	N/A
	Richmond	Standby	Diesel	6400	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Elkton	Standby	Nat gas	6000	No	N/A	N/A
	Southside VA	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	#2 FO	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	50	No	N/A	N/A
	Vienna	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	200	No	N/A	N/A
	Norfolk	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Norfolk	Standby	Diesel	1500	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Newport News	Standby	Diesel	750	No	N/A	N/A
	Chesterfield	Standby	Coal	500	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1000	No	N/A	N/A
	Northern VA	Standby	Diesel	3000	No	N/A	N/A
	Richmond Metro	Standby	NG	25000	No	N/A	N/A
	Suffolk	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	21000	No	N/A	N/A
	Richmond	Standby	Diesel	500	No	N/A	N/A
	Hampton Roads	Standby	Diesel	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Hampton Roads	Standby	Diesel	12000	No	N/A	N/A
	West Point	Standby	Unknown	50000	No	N/A	N/A
	Northern VA	Standby	Diesel	100	No	N/A	N/A
	Herndon	Standby	Diesel	18100	No	N/A	N/A
	VA	Merchant	RDF	60000	No	N/A	N/A
	Stafford	Standby	Diesel	3000	No	N/A	N/A
	Chesterfield	Standby	Diesel	750	No	N/A	N/A
	Henrico	Standby	Diesel	750	No	N/A	N/A
	Richmond	Standby	Diesel	5150	No	N/A	N/A
	Culpepper	Standby	Diesel	7000	No	N/A	N/A
	Richmond	Standby	Diesel	8000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Northern VA	Standby	Diesel	6000	No	N/A	N/A
	Northern VA	Standby	Diesel	500	No	N/A	N/A
	Northern VA	Standby	NG	50000	No	N/A	N/A

Appendix 3B cont. – Other Generation Units

Company Name: Virginia Electric and Power Company **Schedule 14b**

UNIT PERFORMANCE DATA

Existing Supply-Side Resources (kW)

Unit Name	Location	Unit Class	Primary Fuel Type	kW Summer	Capacity Resource	Contract Start	Contract Expiration
Customer Owned[3]							
	Hampton Roads	Standby	Unknown	4000	No	N/A	N/A
	Northern VA	Standby	Diesel	10000	No	N/A	N/A
	Northern VA	Standby	Diesel	13000	No	N/A	N/A
	Southside VA	Standby	Water	227000	No	N/A	N/A
	Northern VA	Standby	Diesel	300	No	N/A	N/A
	Northern VA	Standby	Diesel	1000	No	N/A	N/A
	Richmond	Standby	Diesel	1500	No	N/A	N/A
	Richmond	Standby	Diesel	30	No	N/A	N/A
	Newport News	Standby	Diesel	1000	No	N/A	N/A
	Hampton	Standby	Diesel	12000	No	N/A	N/A
	Newport News	Standby	Natural gas	3000	No	N/A	N/A
	Newport News	Standby	Diesel	2000	No	N/A	N/A
	Petersburg	Standby	Diesel	1750	No	N/A	N/A
	Various	Standby	Diesel	3000	No	N/A	N/A
	Various	Standby	Diesel	30000	No	N/A	N/A
	Northern VA	Standby	Diesel	5000	No	N/A	N/A
	Northern VA	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	16000	No	N/A	N/A
	Northern VA	Standby	Diesel	6450	No	N/A	N/A
	Virginia Beach	Standby	Diesel	2000	No	N/A	N/A
	Ashburn	Standby	Diesel	12 - 2000	No	N/A	N/A
	Innsbrook-Richmond	Standby	Diesel	6050	No	N/A	N/A
	Northern VA	Standby	Diesel	150	No	N/A	N/A
	Henrico	Standby	Diesel	500	No	N/A	N/A
	Virginia Beach	Standby	Diesel	1500	No	N/A	N/A
	Ahoskie	Standby	Diesel	2550	No	N/A	N/A
	Tillery	Standby	Diesel	585	No	N/A	N/A
	Whitakers	Standby	Diesel	10000	No	N/A	N/A
	Columbia	Standby	Diesel	400	No	N/A	N/A
	Grandy	Standby	Diesel	400	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	500	No	N/A	N/A
	Moyock	Standby	Diesel	350	No	N/A	N/A
	Nags Head	Standby	Diesel	400	No	N/A	N/A
	Nags Head	Standby	Diesel	450	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	400	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Conway	Standby	Diesel	500	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	500	No	N/A	N/A
	Corolla	Standby	Diesel	700	No	N/A	N/A
	Kill Devil Hills	Standby	Diesel	700	No	N/A	N/A
	Rocky Mount	Standby	Diesel	700	No	N/A	N/A
	Roanoke Rapids	Standby	Coal	30000	No	N/A	N/A
	Manteo	Standby	Diesel	300	No	N/A	N/A
	Conway	Standby	Diesel	800	No	N/A	N/A
	Lewiston	Standby	Diesel	4000	No	N/A	N/A
	Roanoke Rapids	Standby	Diesel	1200	No	N/A	N/A
	Weldon	Standby	Diesel	750	No	N/A	N/A
	Tillery	Standby	Diesel	450	No	N/A	N/A
	Elizabeth City	Standby	Unknown	2000	No	N/A	N/A
	Greenville	Standby	Diesel	1800	No	N/A	N/A

Appendix 3C – Equivalent Availability Factor for Plan E: Federal CO_2 Program (%)

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Altavista	67	63	63	77	78	78	78	78	74	74	74	74	74	74	74	74	74	74	74
Bath County 1-6	77	80	90	93	94	94	94	95	95	95	95	95	95	95	95	95	95	98	98
Bear Garden	81	85	80	89	80	86	84	84	88	89	88	90	89	88	89	78	78	87	87
Bellemeade	83	80	74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	78	86	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	80	83	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	83	82	82	80	83	83	76	93	85	93	79	93	93	85	93	93	84	84
Chesapeake CT 1, 2, 4, 6	92	98	99	91	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	85	86	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	65	75	55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	83	74	65	82	84	81	81	84	86	86	86	86	86	86	86	86	86	86	86
Chesterfield 6	84	74	59	71	85	85	79	85	87	87	87	87	87	87	87	87	87	87	87
Chesterfield 7	90	67	84	73	94	89	96	87	96	91	96	89	96	81	96	91	96	81	87
Chesterfield 8	90	66	85	88	96	73	96	87	96	89	96	89	96	89	96	89	96	80	88
Clover 1	76	88	88	88	83	93	92	94	94	86	92	92	92	92	92	92	92	92	92
Clover 2	90	88	65	92	90	92	83	94	86	94	94	94	94	94	94	94	94	94	94
CVOW	-	-	-	-	-	-	45	45	45	45	45	45	45	45	45	45	45	45	45
Darbytown 1	96	91	92	93	83	93	93	93	88	88	88	88	88	88	88	88	88	93	93
Darbytown 2	80	97	93	95	84	94	94	94	90	90	90	90	90	90	90	90	90	93	93
Darbytown 3	91	98	89	95	84	94	94	94	90	90	90	90	90	90	90	90	90	93	93
Darbytown 4	92	92	92	95	84	94	94	94	90	90	90	90	90	90	90	90	90	93	93
Elizabeth River 1	99	98	93	95	91	94	94	94	89	89	89	89	89	89	89	89	89	90	90
Elizabeth River 2	97	98	92	95	90	94	94	94	89	89	89	89	89	89	89	89	89	90	90
Elizabeth River 3	99	71	92	95	94	91	94	91	90	90	90	90	90	90	90	90	90	90	90
Existing NC Solar NUGs	20	20	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Existing VA Solar NUGs	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Gaston Hydro	88	90	91	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Generic 2x1 CC				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Aero CT				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Brownfield CT	-	-	-	-	-	-	-	87	87	87	87	87	87	87	87	87	87	87	87
Generic Greenfield CT	-	-	-	-	-	-	-	-	-	87	87	87	87	87	87	87	87	87	87
Generic Solar PV	-	-	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Gordonsville 1	81	89	77	97	84	93	93	86	97	91	97	86	97	91	97	86	97	87	93
Gordonsville 2	83	91	52	97	93	93	86	89	97	91	97	84	91	97	91	97	91	93	93
Gravel Neck 1-2	96	96	100	91	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	89	96	90	95	94	94	94	91	90	90	90	90	90	90	90	90	90	94	94
Gravel Neck 4	90	97	87	95	91	94	94	94	90	90	90	90	90	90	90	90	90	94	94
Gravel Neck 5	92	97	91	92	94	94	94	94	90	90	90	90	90	90	90	90	90	94	94
Gravel Neck 6	91	97	91	95	94	94	94	91	90	90	90	90	90	90	90	90	90	94	94

Note: EAF for intermittent resources shown as a capacity factor.

Appendix 3C cont. – Equivalent Availability Factor for Plan E: Federal CO_2 Program (%)

Company Name: Virginia Electric and Power Company **Schedule 8**

UNIT PERFORMANCE DATA

Equivalent Availability Factor (%)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Greensville	-	-	-	96	82	83	83	83	90	90	90	90	90	90	90	90	90	84	84
Hopewell	64	74	78	77	78	78	78	77	74	74	74	74	74	74	74	74	74	74	74
Ladysmith 1	93	90	85	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 2	92	90	85	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 3	94	91	84	80	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 4	94	91	77	71	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Ladysmith 5	94	90	83	90	80	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Lowmoor CT 1-4	98	98	98	91	91	100	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	84	95	93	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	82	96	93	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	80	82	74	72	68	83	78	72	75	83	81	75	83	81	75	83	81	86	86
Mount Storm 2	78	80	81	72	81	79	72	81	75	81	81	75	81	81	75	81	86	86	86
Mount Storm 3	79	65	70	87	81	73	82	73	75	84	84	75	84	84	75	84	87	87	87
Mount Storm CT	57	100	96	91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	92	90	100	89	92	98	91	91	98	91	91	98	91	91	98	91	91	98	91
North Anna 2	100	88	90	98	89	91	98	91	91	98	91	91	98	91	91	98	91	91	91
North Anna Hydro	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Northern Neck CT 1-4	100	98	94	91	90	90	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	88	60	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	89	71	85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	83	69	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	33	52	62	81	80	80	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	80	80	75	91	77	84	80	80	88	88	88	76	88	88	88	88	88	87	87
Possum Point CT 1-6	100	99	97	91	90	90	100	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	91	91	91	91	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Remington 2	86	92	91	91	90	90	87	90	90	90	90	90	90	90	90	90	90	90	90
Remington 3	89	90	70	91	90	90	87	87	90	90	90	90	90	90	90	90	90	90	90
Remington 4	92	92	83	91	90	87	90	90	90	90	90	90	90	90	90	90	90	90	90
Roanoke Rapids Hydro	88	90	93	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Rosemary	68	81	77	94	96	83	96	96	89	96	89	96	89	96	89	96	89	94	94
Scott Solar	-	2	21	25	25	24	24	24	24	24	24	24	24	23	23	23	23	23	23
SEI Birchwood	90	90	87	80	80	80	74	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Southampton	74	69	68	78	77	79	77	77	74	74	74	74	74	74	74	74	74	74	74
Surry 1	75	94	99	91	90	98	91	91	98	91	91	98	91	91	98	91	91	93	93
Surry 2	81	99	92	89	98	91	91	98	91	91	98	91	91	98	91	91	98	98	93
US-3 Solar 1	-	-	-	-	-	28	28	28	28	28	28	28	28	28	28	28	28	28	28
US-3 Solar 2	-	-	-	-	-	-	27	27	27	27	27	27	27	27	27	27	27	27	27
Virginia City Hybrid Energy Center	66	76	74	76	75	80	77	80	77	77	77	77	77	77	71	77	77	88	88
Warren	61	81	88	79	83	83	75	83	85	93	93	77	89	86	93	93	93	85	85
Whitehouse Solar	-	2	20	25	25	25	25	24	24	24	24	24	24	24	24	23	23	23	23
Woodland Solar	-	2	18	25	25	25	25	25	25	25	24	24	24	24	24	24	24	24	24
Yorktown 1	79	87	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	84	91	97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	35	59	83	82	81	81	81	-	-	-	-	-	-	-	-	-	-	-	-

Note: EAF for intermittent resources shown as a capacity factor.

Appendix 3D – Net Capacity Factor for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 9**
UNIT PERFORMANCE DATA
Net Capacity Factor (%)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Altavista	60.1	63.1	61.7	75.2	75.2	74.9	73.6	74.8	11.5	11.6	12.9	16.0	17.5	16.3	18.2	18.1	20.6	21.8	29.3
Bath County 1-6	13.8	12.3	14.2	24.3	23.7	20.9	19.7	19.8	19.6	19.7	19.3	18.8	18.3	18.4	18.7	18.6	18.2	17.7	18.0
Bear Garden	67.0	69.7	62.1	78.1	70.6	72.3	71.8	72.5	72.4	75.5	74.7	76.2	74.6	65.4	64.8	49.0	48.1	55.1	57.9
Bellemeade	53.2	39.9	7.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	6.5	10.3	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	12.7	24.6	8.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	51.0	67.8	74.7	73.3	79.2	77.6	71.5	85.6	79.0	83.6	74.2	84.0	81.6	77.4	79.3	79.7	70.1	73.6
Chesapeake CT 1, 2, 4, 6	0.2	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	12.6	6.2	4.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	23.4	53.7	16.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	69.8	59.4	43.4	29.1	25.7	24.2	21.1	18.6	18.2	17.4	16.8	17.3	18.9	14.6	15.3	12.2	12.1	10.9	11.6
Chesterfield 6	69.8	63.0	31.3	26.8	31.3	32.9	25.9	23.7	22.4	22.3	21.3	23.9	25.8	20.3	20.4	17.3	15.8	14.2	16.2
Chesterfield 7	94.7	70.6	89.7	64.8	86.6	80.6	86.9	78.1	84.1	78.8	82.6	75.6	81.6	64.7	79.1	70.9	75.8	61.6	70.0
Chesterfield 8	96.4	69.7	90.2	81.8	87.9	65.0	84.2	76.8	81.4	76.2	79.4	73.5	79.1	70.9	76.0	68.3	71.9	59.2	66.8
Clover 1	65.3	69.4	48.0	41.2	39.8	43.7	39.5	37.2	38.8	35.9	18.4	18.7	19.9	15.0	14.1	11.7	11.3	10.1	10.8
Clover 2	77.5	72.0	37.1	46.4	44.4	47.5	41.6	42.7	40.9	43.5	19.8	21.5	23.1	17.4	18.5	13.4	13.8	12.2	14.3
CVOW	-	-	-	-	-	-	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8
Darbytown 1	4.2	0.9	1.9	3.5	3.5	2.8	1.9	1.6	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Darbytown 2	3.1	0.9	1.8	3.5	3.5	2.9	1.9	1.8	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Darbytown 3	5.2	1.2	2.7	3.5	3.5	2.9	2.1	1.8	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Darbytown 4	5.9	1.4	8.7	3.5	3.5	2.9	1.9	1.8	1.3	2.0	1.5	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Elizabeth River 1	7.2	3.7	3.4	4.6	4.6	4.2	4.5	4.0	3.7	3.8	3.7	3.2	3.4	3.2	3.2	3.3	3.3	3.1	3.2
Elizabeth River 2	6.1	7.0	3.5	4.6	4.6	4.2	4.5	4.0	3.7	3.8	3.7	3.2	3.4	3.2	3.2	3.3	3.3	3.1	3.2
Elizabeth River 3	0.9	5.0	3.2	4.6	4.6	4.2	4.5	4.0	3.7	3.8	3.6	3.2	3.4	3.2	3.2	3.2	3.2	3.1	3.2
Existing NC Solar NUGs	-	-	-	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Existing VA Solar NUGs	-	-	-	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Gaston Hydro	16.4	21.2	14.1	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Generic 2x1 CC				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Aero CT	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Brownfield CT	-	-	-	-	-	-	-	7.0	7.1	7.7	8.0	9.3	7.7	5.9	6.0	5.1	4.5	4.8	5.8
Generic Greenfield CT	-	-	-	-	-	-	-	-	-	7.5	8.0	9.3	7.8	6.4	6.7	5.8	5.1	5.3	6.2
Generic Solar PV	-	-	-	-	-	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Gordonsville 1	57.8	47.1	14.2	53.4	45.3	42.0	36.2	36.1	38.7	41.0	40.4	36.0	39.5	31.9	36.5	27.0	29.9	24.8	31.0
Gordonsville 2	61.7	48.9	9.6	55.0	55.1	43.3	36.5	41.6	41.1	43.4	42.0	40.1	37.7	35.6	37.4	32.8	31.8	27.7	34.0
Gravel Neck 1-2	-	0.1	0.1	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	1.1	5.3	4.3	5.9	5.9	5.1	5.2	5.0	4.7	4.9	5.1	4.7	4.7	4.5	4.5	4.2	4.2	4.0	4.3
Gravel Neck 4	4.5	5.4	0.9	5.9	5.9	5.1	5.2	5.0	4.7	5.0	5.1	4.7	4.7	4.6	4.5	4.2	4.2	4.0	4.3
Gravel Neck 5	3.6	5.1	3.9	5.9	5.9	5.1	5.2	5.0	4.7	4.9	5.1	4.7	4.7	4.5	4.5	4.2	4.2	4.0	4.3
Gravel Neck 6	3.0	2.7	0.8	5.9	5.9	5.1	5.2	5.0	4.7	5.0	5.1	4.7	4.7	4.6	4.5	4.2	4.2	4.0	4.3

Appendix 3D cont. – Net Capacity Factor for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 9**
UNIT PERFORMANCE DATA
Net Capacity Factor (%)

	(ACTUAL)				(PROJECTED)														
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Greensville	-	-	-	8.0	78.9	79.6	79.7	79.8	86.0	86.2	85.4	85.3	85.6	84.5	85.3	85.1	84.5	78.8	79.9
Hopewell	58.8	68.3	66.0	68.8	64.9	67.6	65.3	66.9	9.2	8.7	8.7	10.2	12.4	11.4	12.4	13.7	16.1	16.4	22.3
Ladysmith 1	4.1	7.0	9.4	10.1	10.1	10.0	10.1	10.1	10.1	9.6	9.8	9.9	10.0	8.1	8.6	8.5	8.8	7.6	7.9
Ladysmith 2	3.3	15.3	11.1	10.1	10.1	10.0	10.1	10.1	10.1	9.6	9.8	9.8	10.1	8.1	8.8	8.5	8.7	7.5	7.9
Ladysmith 3	10.1	11.4	5.7	10.1	10.1	10.0	10.1	10.1	10.1	10.0	9.9	9.9	10.1	8.3	8.9	8.6	8.9	7.6	8.2
Ladysmith 4	9.4	9.6	9.4	9.4	10.1	10.0	10.1	10.1	10.1	9.9	9.9	9.7	10.1	8.3	9.2	8.6	9.0	7.6	8.1
Ladysmith 5	5.3	12.8	6.5	10.1	9.8	10.0	10.1	10.1	10.1	10.0	9.9	10.0	10.1	8.3	9.2	8.6	9.0	7.6	8.1
Lowmoor CT 1-4	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	28.0	25.6	12.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	27.6	23.8	12.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	70.3	68.4	49.4	50.1	47.0	59.0	53.5	52.1	52.0	49.0	47.5	48.6	52.3	46.0	46.3	42.8	38.1	36.9	40.1
Mount Storm 2	65.9	67.0	58.0	50.8	56.0	57.7	52.5	55.3	52.3	48.2	48.4	48.3	51.7	46.7	46.9	42.5	38.8	36.8	39.8
Mount Storm 3	70.9	53.3	39.1	55.6	50.2	47.8	47.7	43.9	42.6	43.2	41.6	42.2	46.9	40.3	38.2	33.9	32.7	29.9	33.3
Mount Storm CT	0.1	0.2	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	93.8	91.6	102.3	87.3	90.6	96.3	89.1	89.0	96.3	88.9	89.0	96.3	88.8	89.0	96.3	88.8	89.0	96.3	88.8
North Anna 2	102.6	90.4	92.3	96.4	87.3	89.4	96.4	89.0	89.1	96.4	88.9	89.1	96.4	88.9	89.1	96.4	88.9	89.1	88.9
North Anna Hydro	41.4	41.4	29.2	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6
Northern Neck CT 1-4	-	0.1	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	36.8	20.1	15.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	1.3	2.2	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	1.4	3.5	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	3.5	1.3	0.9	6.0	6.0	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	66.4	67.2	59.1	85.5	72.5	78.8	74.2	74.6	80.4	80.0	79.0	67.6	78.5	75.7	76.4	75.0	74.1	70.6	73.4
Possum Point CT 1-6	-	0.0	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	18.4	13.0	9.9	17.3	15.1	10.9	9.1	9.2	9.1	9.2	9.4	8.6	8.3	7.2	7.7	7.7	7.5	7.3	7.3
Remington 2	16.6	14.0	9.8	17.3	15.2	10.9	9.1	9.1	9.1	9.1	9.4	8.7	8.3	7.2	7.6	7.7	7.5	7.2	7.3
Remington 3	15.7	11.0	10.0	17.5	16.1	11.3	9.1	9.3	9.4	9.3	9.5	8.8	8.4	7.4	7.8	7.7	7.6	7.1	7.3
Remington 4	16.5	12.1	8.7	16.3	16.0	11.1	10.3	10.7	10.5	10.3	10.5	10.2	9.4	8.2	8.7	8.6	8.5	8.1	8.2
Roanoke Rapids Hydro	34.9	43.1	25.7	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4	30.4
Rosemary	7.8	5.2	9.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Scott Solar	-	2.1	20.6	24.7	24.6	24.4	24.3	24.2	24.1	23.9	23.8	23.7	23.6	23.5	23.4	23.2	23.1	23.0	22.9
SEI Birchwood	27.2	21.6	22.8	52.2	53.8	50.1	41.3	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Southampton	65.0	66.1	62.5	61.0	52.7	55.0	50.3	54.1	6.1	6.2	6.5	6.6	8.2	6.9	8.8	8.3	9.7	10.7	16.0
Surry 1	77.2	96.6	102.4	89.2	87.9	95.9	88.7	88.4	95.9	88.7	88.4	95.9	88.7	88.4	95.9	88.7	88.4	91.0	91.0
Surry 2	83.4	101.9	94.2	87.3	95.9	89.0	88.4	95.9	88.7	88.4	95.9	88.7	88.4	95.9	88.7	88.4	95.9	95.9	91.0
US-3 Solar 1	-	-	-	-	-	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
US-3 Solar 2	-	-	-	-	-	-	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2
Virginia City Hybrid Energy Center	55.5	65.4	62.4	58.7	55.7	63.7	62.1	64.5	62.8	57.7	59.8	64.3	62.6	58.6	58.1	56.6	55.1	52.9	54.3
Warren	54.7	72.3	75.7	72.3	74.4	75.3	65.7	74.7	75.4	82.5	81.8	69.2	77.0	72.0	77.7	74.4	75.0	66.9	70.6
Whitehouse Solar	-	2.1	19.9	24.9	24.8	24.6	24.5	24.4	24.3	24.2	24.0	23.9	23.8	23.7	23.6	23.5	23.3	23.2	23.1
Woodland Solar	-	2.1	17.8	25.3	25.2	25.1	25.0	24.8	24.7	24.6	24.5	24.3	24.2	24.1	24.0	23.9	23.7	23.6	23.5
Yorktown 1	10.5	3.4	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	8.0	19.7	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	4.4	2.1	1.1	3.0	3.0	3.0	3.0	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 3E – Heat Rates for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 10**

UNIT PERFORMANCE DATA

Average Heat Rate - (mmBtu/MWh)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Altavista	14.26	15.07	15.16	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31
Bath County 1-6			-																
Bear Garden	7.12	6.79	6.54	7.13	7.12	7.12	7.12	7.13	7.13	7.12	7.12	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13
Bellemeade	8.62	8.72	8.77																
Bremo 3	12.06	12.37	12.30																
Bremo 4	10.59	10.45	10.54																
Brunswick	-	8.34	6.96	6.88	6.88	6.88	6.88	6.88	6.88	6.86	6.87	6.84	6.87	6.87	6.86	6.87	6.87	6.87	6.87
Chesapeake CT 1, 2, 4, 6	16.98	16.98	16.90	0.00	0.00														
Chesterfield 3	12.45	13.05	13.68																
Chesterfield 4	10.52	10.46	11.07																
Chesterfield 5	10.16	10.27	10.23	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86
Chesterfield 6	9.98	10.07	10.25	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94
Chesterfield 7	7.40	7.45	7.53	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33	7.33
Chesterfield 8	7.23	7.30	7.38	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25	7.25
Clover 1	9.99	10.06	10.31	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53	10.53
Clover 2	10.00	10.06	10.21	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44
CVOW																			
Darbytown 1	12.54	12.60	12.45	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04
Darbytown 2	12.56	12.47	12.35	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03
Darbytown 3	12.51	12.38	12.36	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02	12.02
Darbytown 4	12.58	12.48	12.43	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03	12.03
Elizabeth River 1	11.69	11.86	12.06	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14	12.14
Elizabeth River 2	11.72	12.12	12.24	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Elizabeth River 3	11.23	12.32	12.11	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15	12.15
Existing NC Solar NUGs																			
Existing VA Solar NUGs																			
Gaston Hydro																			
Generic 2x1 CC																			
Generic Aero CT																			
Generic Brownfield CT								10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07
Generic Greenfield CT										10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07	10.07
Generic Solar PV																			
Gordonsville 1	8.47	8.17	8.60	8.16	8.17	8.16	8.16	8.17	8.16	8.16	8.16	8.17	8.16	8.16	8.16	8.17	8.16	8.16	8.16
Gordonsville 2	8.45	8.17	8.51	8.15	8.15	8.15	8.15	8.16	8.15	8.15	8.15	8.15	8.16	8.15	8.15	8.15	8.15	8.15	8.15
Gravel Neck 1-2	20.17	19.08	17.86	17.40	0.00														
Gravel Neck 3	12.79	12.57	12.61	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35
Gravel Neck 4	12.82	12.57	13.02	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34
Gravel Neck 5	13.22	12.99	13.09	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35	12.35
Gravel Neck 6	12.55	12.72	12.79	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34	12.34

Appendix 3E cont. – Heat Rates for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 10**
UNIT PERFORMANCE DATA
Average Heat Rate - (mmBtu/MWh)

	(ACTUAL)			(PROJECTED)															
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Greensville	-		-	6.44	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67
Hopewell	15.75	15.32	15.98	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09	12.09
Ladysmith 1	10.09	10.06	9.96	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 2	9.86	9.68	9.70	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 3	9.94	9.89	9.99	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 4	9.86	9.92	9.84	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Ladysmith 5	9.90	9.83	9.98	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31	10.31
Lowmoor CT 1-4	17.83	16.59	16.86	0.00	0.00	0.00													
Mecklenburg 1	11.89	11.95	12.49																
Mecklenburg 2	12.20	12.36	12.50																
Mount Storm 1	9.99	10.13	10.16	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86	9.86
Mount Storm 2	9.93	10.07	10.05	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91	9.91
Mount Storm 3	10.42	10.39	10.56	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19
Mount Storm CT	21.83	16.75	16.03	0.00	0.00														
North Anna 1	-	-		10.40	10.39	10.40	10.40	10.39	10.40	10.41	10.39	10.40	10.41	10.39	10.40	10.41	10.39	10.40	10.41
North Anna 2	-	-		10.42	10.44	10.41	10.42	10.43	10.41	10.42	10.43	10.41	10.42	10.43	10.41	10.42	10.44	10.41	10.44
North Anna Hydro																			
Northern Neck CT 1-4	18.19	16.32	16.87	0.00	0.00	0.00													
Pittsylvania	15.98	17.36	14.76																
Possum Point 3	12.21	12.95	11.62																
Possum Point 4	12.96	11.49	11.66																
Possum Point 5	10.26	11.19	11.87	9.93	9.93	9.93													
Possum Point 6	7.19	7.13	7.18	7.43	7.42	7.42	7.39	7.38	7.41	7.40	7.40	7.38	7.40	7.39	7.39	7.39	7.39	7.38	7.39
Possum Point CT 1-6	17.04	17.96	17.32	0.00	0.00	0.00	0.00												
Remington 1	9.97	10.02	10.01	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Remington 2	10.17	10.05	10.10	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Remington 3	10.30	10.26	10.03	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Remington 4	10.12	10.09	9.99	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Roanoke Rapids Hydro																			
Rosemary	9.55	9.50	9.48	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76
Scott Solar																			
SEI Birchwood	10.00	10.00	10.00	9.61	9.61	9.61	9.61												
Solar Partnership Program																			
Southampton	15.16	15.31	15.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70	11.70
Surry 1	-	-		10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.31
Surry 2	-	-		10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.29	10.33	10.31	10.31	10.31
US-3 Solar 1																			
US-3 Solar 2																			
Virginia City Hybrid Energy Center	9.96	9.87	10.02	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39	9.39
Warren	6.77	6.91	6.88	6.93	6.93	6.94	6.93	6.92	6.93	6.94	6.93	6.94	6.93	6.93	6.94	6.94	6.94	6.95	6.94
Whitehouse Solar																			
Woodland Solar																			
Yorktown 1	10.70	11.54	12.09																
Yorktown 2	10.66	11.63	12.25																
Yorktown 3	10.79	10.55	10.86	10.15	10.15	10.15	10.15												

Appendix 3F – Existing Capacity for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 7**

CAPACITY DATA

	(ACTUAL)			(PROJECTED)															
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
I. Installed Capacity (MW)(1)																			
a. Nuclear	3,357	3,357	3,357	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349
b. Coal	4,400	4,081	4,077	3,638	3,644	3,638	3,632	3,626	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623	3,623
c. Heavy Fuel Oil	1,575	1,575	1,572	1,576	1,576	1,576	790	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	596	596	596	246	167	119	47	47	47	47	47	47	47	47	47	47	47	47	47
e. Natural Gas-Boiler	543	543	543	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f. Natural Gas-Combined Cycle	3,543	4,919	4,948	4,693	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278	6,278
g. Natural Gas-Turbine	2,052	2,053	2,053	2,426	2,426	2,426	2,426	2,884	3,342	3,800	4,258	4,716	4,716	4,716	5,174	5,632	6,090	6,090	6,090
h. Hydro-Conventional	317	317	317	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
i. Pumped Storage	1,809	1,809	1,809	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
j. Renewable	236	236	236	213	207	318	439	554	665	756	864	973	1,081	1,190	1,280	1,353	1,371	1,479	1,588
k. Total Company Installed	18,428	19,486	19,509	18,265	19,771	19,828	19,085	18,861	19,428	19,976	20,543	21,109	21,218	21,326	21,875	22,405	22,881	22,990	23,098
l. Other (NUG)	1,775	1,252	238	346	366	372	372	153	152	152	151	150	149	149	148	147	146	145	144
n. Total	20,203	20,738	19,746	18,611	20,137	20,201	19,456	19,014	19,580	20,128	20,694	21,259	21,367	21,475	22,023	22,552	23,028	23,134	23,242
II. Installed Capacity Mix (%)(2)																			
a. Nuclear	16.6%	16.2%	17.0%	18.0%	16.6%	16.6%	17.2%	17.6%	17.1%	16.6%	16.2%	15.8%	15.7%	15.6%	15.2%	14.8%	14.5%	14.5%	14.4%
b. Coal	21.8%	19.7%	20.6%	19.5%	18.1%	18.0%	18.7%	19.1%	18.5%	18.0%	17.5%	17.0%	17.0%	16.9%	16.4%	16.1%	15.7%	15.7%	15.6%
c. Heavy Fuel Oil	7.8%	7.6%	8.0%	8.5%	7.8%	7.8%	4.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
d. Light Fuel Oil	3.0%	2.9%	3.0%	1.3%	0.8%	0.6%	0.2%	0.00	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas-Boiler	2.7%	2.6%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
f. Natural Gas-Combined Cycle	17.5%	23.7%	25.1%	25.2%	31.2%	31.1%	32.3%	33.0%	32.1%	31.2%	30.3%	29.5%	29.4%	29.2%	28.5%	27.8%	27.3%	27.1%	27.0%
g. Natural Gas-Turbine	10.2%	9.9%	10.4%	13.0%	12.0%	12.0%	12.5%	15.2%	17.1%	18.9%	20.6%	22.2%	22.1%	22.0%	23.5%	25.0%	26.4%	26.3%	26.2%
h. Hydro-Conventional	1.6%	1.5%	1.6%	1.7%	1.6%	1.6%	1.6%	1.7%	1.6%	1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%
i. Pumped Storage	9.0%	8.7%	9.2%	9.7%	9.0%	9.0%	9.3%	9.5%	9.2%	9.0%	8.7%	8.5%	8.5%	8.4%	8.2%	8.0%	7.9%	7.8%	7.8%
j. Renewable	1.2%	1.1%	1.2%	1.1%	1.0%	1.6%	2.3%	2.9%	3.4%	3.8%	4.2%	4.6%	5.1%	5.5%	5.8%	6.0%	6.0%	6.4%	6.8%
k. Total Company Installed	91.2%	94.0%	98.8%	98.1%	98.2%	98.2%	98.1%	99.2%	99.2%	99.2%	99.3%	99.3%	99.3%	99.3%	99.3%	99.3%	99.4%	99.4%	99.4%
l. Other (NUG)	8.8%	6.0%	1.2%	1.9%	1.8%	1.8%	1.9%	0.8%	0.8%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
n. Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Net dependable installed capability during peak season.

(2) Each item in Section I as a percent of line n (Total).

Appendix 3G – Energy Generation by Type for Plan E: Federal CO_2 Program (GWh)

Company Name: Virginia Electric and Power Company **Schedule 2**

GENERATION

	(ACTUAL)			(PROJECTED)															
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
I. System Output (GWh)																			
a. Nuclear	26,173	27,978	28,683	27,457	27,575	28,331	27,640	27,617	28,207	27,699	27,618	28,207	27,618	27,696	28,207	27,618	27,614	28,461	27,422
b. Coal	22,618	21,974	15,376	15,313	14,578	15,738	14,346	14,131	13,734	13,160	12,211	12,718	13,422	11,725	11,633	10,529	9,886	9,326	10,030
c. Heavy Fuel Oil	542	236	141	631	631	633	208	0	0	0	0	0	0	0	0	0	0	0	0
d. Light Fuel Oil	319	222.8	131.1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Natural Gas-Boiler	253	487.5	163.4	554	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f. Natural Gas-Combined Cycle	18,482	25,563	26,832	33,339	43,340	44,093	42,676	42,822	46,212	46,399	46,682	43,004	46,045	43,757	44,395	42,736	42,864	39,420	41,168
g. Natural Gas-Turbine	1,606	1,692	1,246	2,386	2,294	1,940	1,807	2,089	2,356	2,749	3,121	3,654	3,327	2,774	3,169	3,140	3,185	3,128	3,487
h. Hydro-Conventional	1,039	1,333	876	513	513	514	513	513	513	514	513	513	513	514	513	513	513	514	513
i. Hydro-Pumped Storage	2,217	1,971	2,367	3,850	3,748	3,323	3,120	3,143	3,101	3,137	3,050	2,977	2,906	2,918	2,970	2,941	2,887	2,813	2,853
j. Renewable(1)	1,191	1,246	1,265	1,684	1,252	2,419	3,548	4,657	4,958	5,833	6,900	8,012	9,092	10,149	11,026	11,730	11,926	13,028	14,147
k. Total Generation	74,440	82,703	77,081	85,727	93,932	96,991	93,858	94,972	99,081	99,491	100,094	99,084	102,923	99,533	101,912	99,206	98,876	96,690	99,621
l. Purchased Power	14,657	7,486	13,419	14,351	9,917	8,648	10,356	9,341	8,080	9,041	8,905	11,260	9,746	12,530	11,502	14,611	15,599	17,885	16,622
m. Total Payback Energy(2)	-			9	7	8	8	8	7	8	6	9	9	11	11	11	11	11	11
n. Less Pumping Energy	-2,800	-2,480	-3,014	-4,813	-4,685	-4,135	-3,900	-3,929	-3,885	-3,932	-3,794	-3,722	-3,632	-3,656	-3,723	-3,676	-3,607	-3,499	-3,567
o. Less Other Sales(3)	-1,716	-4,296	-1,536	-7,303	-10,030	-12,220	-9,628	-8,151	-9,509	-9,018	-8,229	-8,034	-8,927	-6,560	-6,729	-5,942	-5,359	-4,002	-4,777
p. Total System Firm Energy Req.	84,581	83,414	85,951	87,963	89,134	89,283	90,687	92,233	93,767	95,583	96,976	98,587	100,109	101,847	102,962	104,200	105,508	107,075	107,898
II. Energy Supplied by Competitive Service Providers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Include current estimates for renewable energy generation by VCHEC.

(2) Payback Energy is accounted for in Total Generation.

(3) Include all sales or delivery transactions with other electric utilities, i.e., firm or economy sales, etc.

Appendix 3H – Energy Generation by Type for Plan E: Federal CO_2 Program (%)

Company Name: Virginia Electric and Power Company **Schedule 3**

GENERATION

	(ACTUAL)			(PROJECTED)															
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
III. System Output Mix (%)																			
a. Nuclear	30.9%	33.5%	33.4%	31.2%	30.9%	31.7%	30.5%	29.9%	30.1%	29.0%	28.5%	28.6%	27.6%	27.2%	27.4%	26.5%	26.2%	26.6%	25.4%
b. Coal	26.7%	26.3%	17.9%	17.4%	16.4%	17.6%	15.8%	15.3%	14.6%	13.8%	12.6%	12.9%	13.4%	11.5%	11.3%	10.1%	9.4%	8.7%	9.3%
c. Heavy Fuel Oil	0.6%	0.3%	0.2%	0.7%	0.7%	0.7%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
d. Light Fuel Oil	0.4%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
e. Natural Gas-Boiler	0.3%	0.6%	0.2%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
f. Natural Gas-Combined Cycle	21.9%	30.6%	31.2%	37.9%	48.6%	49.4%	47.1%	46.4%	49.3%	48.5%	48.1%	43.6%	46.0%	43.0%	43.1%	41.0%	40.6%	36.8%	38.2%
g. Natural Gas-Turbine	1.9%	2.0%	1.4%	2.7%	2.6%	2.2%	2.0%	2.3%	2.5%	2.9%	3.2%	3.7%	3.3%	2.7%	3.1%	3.0%	3.0%	2.9%	3.2%
h. Hydro-Conventional	1.2%	1.6%	1.0%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
i. Hydro-Pumped Storage	2.6%	2.4%	2.8%	4.4%	4.2%	3.7%	3.4%	3.4%	3.3%	3.3%	3.1%	3.0%	2.9%	2.9%	2.9%	2.8%	2.7%	2.6%	2.6%
j. Renewable Resources	1.4%	1.5%	1.5%	1.9%	1.4%	2.7%	3.9%	5.0%	5.3%	6.1%	7.1%	8.1%	9.1%	10.0%	10.7%	11.3%	11.3%	12.2%	13.1%
k. Total Generation	88.0%	99.1%	89.7%	97.5%	105.4%	108.6%	103.5%	103.0%	105.7%	104.1%	103.2%	100.5%	102.8%	97.7%	99.0%	95.2%	93.7%	90.3%	92.3%
l. Purchased Power	17.3%	9.0%	15.6%	16.3%	11.1%	9.7%	11.4%	10.1%	8.6%	9.5%	9.2%	11.4%	9.7%	12.3%	11.2%	14.0%	14.8%	16.7%	15.4%
m. Direct Load Control (DLC)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
n. Less Pumping Energy	-3.3%	-3.0%	-3.5%	-5.5%	-5.3%	-4.6%	-4.3%	-4.3%	-4.1%	-4.1%	-3.9%	-3.8%	-3.6%	-3.6%	-3.6%	-3.5%	-3.4%	-3.3%	-3.3%
o. Less Other Sales(1)	-2.0%	-5.1%	-1.8%	-8.3%	-11.3%	-13.7%	-10.6%	-8.8%	-10.1%	-9.4%	-8.5%	-8.1%	-8.9%	-6.4%	-6.5%	-5.7%	-5.1%	-3.7%	-4.4%
p. Total System Output	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IV. System Load Factor	58.5%	57.9%	58.6%	57.7%	57.6%	57.3%	57.5%	57.7%	57.8%	57.3%	57.3%	57.3%	57.5%	57.8%	57.7%	57.4%	57.5%	57.8%	57.9%

(1) Economy energy.

Appendix 3I – Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company **Schedule 13a**

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)														
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Altavista	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bath County 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bear Garden	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bellemeade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bremo 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brunswick	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesapeake CT 1, 2, 4, 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chesterfield 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clover 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Darbytown 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Elizabeth River 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing NC Solar NUGs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing VA Solar NUGs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gaston Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gordonsville 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 1-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gravel Neck 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-)

Appendix 3I cont. – Planned Changes to Existing Generation Units

Company Name: Virginia Electric and Power Company **Schedule 13a**

UNIT PERFORMANCE DATA[1]

Unit Size (MW) Uprate and Derate

	(ACTUAL)				(PROJECTED)														
Unit Name	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Greensville	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hopewell	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ladysmith 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lowmoor CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mecklenburg 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mount Storm CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Anna Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northern Neck CT 1-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pittsylvania	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point 6	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Possum Point CT 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remington 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Rapids Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roanoke Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rosemary	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scott Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SEI Birchwood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Partnership Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southampton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surry 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Virginia City Hybrid Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Warren	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Whitehouse Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Woodland Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Yorktown 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

(1) Peak net dependable capability as of this filing. Incremental uprates shown as positive (+) and decremental derates shown as negative (-)

Appendix 3J – Potential Unit Retirements

Company Name: Virginia Electric and Power Company **Schedule 19**
UNIT PERFORMANCE DATA
Planned Unit Retirements(1)

Unit Name	Location	Unit Type	Primary Fuel Type	Projected Retirement Year	MW Summer	MW Winter
Yorktown 1[4]	**Yorktown, VA**	**Steam-Cycle**	**Coal**	**2017**	**159**	**162**
Yorktown 2[4]	**Yorktown, VA**	**Steam-Cycle**	**Coal**	**2017**	**164**	**165**
Chesapeake CT 1	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**15**	**20**
Chesapeake GT1					15	
Chesapeake CT 2	**Chesapeake, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**36**	**49**
Chesapeake GT2					12	
Chesapeake GT4					12	
Chesapeake GT6					12	
Gravel Neck 1	**Surry, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2019**	**28**	**38**
Gravel Neck GT1					12	
Gravel Neck GT2					16	
Lowmoor CT	**Covington, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2020**	**48**	**65**
Lowmoor GT1					12	
Lowmoor GT2					12	
Lowmoor GT3					12	
Lowmoor GT4					12	
Mount Storm CT	**Mt. Storm, WV**	**CombustionTurbine**	**Light Fuel Oil**	**2018**	**11**	**15**
Mt. Storm GT1					11	
Northern Neck CT	**Warsaw, VA**	**CombustionTurbine**	**Light Fuel Oil**	**2020**	**47**	**63**
Northern Neck GT1					12	
Northern Neck GT2					11	
Northern Neck GT3					12	
Northern Neck GT4					12	
Possum Point CT	**Dumfries, VA**	**Steam-Cycle**	**Light Fuel Oil**	**2021**	**72**	**106**
Possum Point CT1					12	
Possum Point CT2					12	
Possum Point CT3					12	
Possum Point CT4					12	
Possum Point CT5					12	
Possum Point CT6					12	
Bellemeade CC[2]	**Richmond, VA**	**Combined Cycle**	**Natural Gas**	**2021**	**267**	**267**
Bremo 3[2]	**New Canton, VA**	**Steam-Cycle**	**Natural Gas**	**2021**	**71**	**71**
Bremo 4[2]	**New Canton, VA**	**Steam-Cycle**	**Natural Gas**	**2021**	**156**	**156**
Clover 1[6]	**Clover, VA**	**Steam-Cycle**	**Coal**	**2025**	**220**	**222**
Clover 2	**Clover, VA**	**Steam-Cycle**	**Coal**	**2025**	**219**	**219**
Chesterfield 3[3]	**Chester, VA**	**Steam-Cycle**	**Coal**	**2021**	**98**	**102**
Chesterfield 4[3]	**Chester, VA**	**Steam-Cycle**	**Coal**	**2021**	**163**	**168**
Chesterfield 5	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**336**	**342**
Chesterfield 6	**Chester, VA**	**Steam-Cycle**	**Coal**	**2023**	**670**	**690**
Mecklenburg 1[2]	**Clarksville, VA**	**Steam-Cycle**	**Coal**	**2021**	**69**	**69**
Mecklenburg 2[2]	**Clarksville, VA**	**Steam-Cycle**	**Coal**	**2021**	**69**	**69**
Pittsylvania[5]	**Hurt, VA**	**Steam-Cycle**	**Biomass**	**2021**	**83**	**83**
Possum Point 3[3]	**Dumfries, VA**	**Steam-Cycle**	**Natural Gas**	**2021**	**96**	**100**
Possum Point 4[3]	**Dumfries, VA**	**Steam-Cycle**	**Natural Gas**	**2021**	**220**	**225**
Possum Point 5	**Dumfries, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2021**	**786**	**805**
Yorktown 3	**Yorktown, VA**	**Steam-Cycle**	**Heavy Fuel Oil**	**2022**	**790**	**792**

(1) Reflects retirement assumptions used for planning purposes, not firm Company commitments.
(2) These units entered into cold reserve in April 2018.
(3) These units are planned to enter into cold reserve in December 2018.
(4) Yorktown Units 1 and 2 ceased operations on April 15, 2017 to comply with the MATS rule. Since that time, PJM requested the units to be available on an emergency basis.
(5) Pittsylvania is planned to enter cold reserve in August 2018.

Appendix 3K – Generation under Construction

Company Name: Virginia Electric and Power Company **Schedule 15a**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Summer(2)	MW Nameplate
Under Construction						
Greensville County Power Station	VA	Intermediate/Baseload	Natural Gas	2019	1,585	1,585

(1) Commercial Operation Date.

(2) Firm capacity.

Appendix 3L – Wholesale Power Sales Contracts

Company Name: Virginia Electric and Power Company **Schedule 20**

WHOLESALE POWER SALES CONTRACTS

			(Actual)				(Projected)														
Entity	**Contract Length**	**Contract Type**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Craig-Botetourt Electric Coop	12-Month Termination Notice	Full Requirements(1)	12	6	10	9	9	9	9	10	10	10	10	11	11	11	11	11	11	11	11
Town of Windsor, North Carolina	12-Month Termination Notice	Full Requirements(1)	11	11	11	10	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12
Virginia Municipal Electric Association	5/31/2031 with annual renewal	Full Requirements(1)	309	350	299	285	287	291	293	295	297	300	302	304	307	311	313	317	320	323	326

(1) Full requirements contracts do not have a specific contracted capacity amount. MWs are included in the Company's load forecast.

Appendix 3M – Description of Active DSM Programs

Air Conditioner Cycling Program

Branded Name:	Smart Cooling Rewards
State:	Virginia & North Carolina
Target Class:	Residential
VA Program Type:	Peak-Shaving
NC Program Type:	Peak-Shaving
VA Duration:	2010 -2043
NC Duration:	2011- 2043

Program Description:
This Program provides participants with an external radio frequency cycling switch that operates on central air conditioners and heat pump systems. Participants allow the Company to cycle their central air conditioning and heat pump systems during peak load periods. The cycling switch is installed by a contractor and located on or near the outdoor air conditioning unit(s). The Company remotely signals the unit when peak load periods are expected, and the air conditioning or heat pump system is cycled off and on for short intervals.

Program Marketing:
The Company uses business reply cards, online enrollment, and call center services.

Non-Residential Distributed Generation Program

Branded Name:	Distributed Generation
State:	Virginia
Target Class:	Non-Residential
VA Program Type:	Demand-Side Management
VA Duration:	2012 – 2043

Program Description:
As part of this Program, a third-party contractor will dispatch, monitor, maintain and operate customer-owned generation when called upon by the Company at anytime for up to a total of 120 hours per year. The Company will supervise and implement the Non-Residential Distributed Generation Program through the third-party implementation contractor. Participating customers will receive an incentive in exchange for their agreement to reduce electrical load on the Company's system when called upon to do so by the Company. The incentive is based upon the amount of load curtailment delivered during control events. When not being dispatched by the Company, the generators may be used at the participants' discretion or to supply power during an outage, consistent with applicable environmental restrictions.

Program Marketing:
Marketing is handled by the Company's implementation vendor.

Appendix 3M cont. – Description of Active DSM Programs

Non-Residential Heating and Cooling Efficiency Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2043
NC Duration:	2015 – 2043

Program Description:
This Program provides qualifying non-residential customers with incentives to implement new and upgrade existing heating, ventilating, and air conditioning ("HVAC") equipment to more efficient HVAC technologies that can produce verifiable savings.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Non-Residential Lighting Systems & Controls Program

Target Class:	Non-Residential
VA Program Type :	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2043
NC Duration:	2015 – 2043

Program Description:
This Program provides qualifying non-residential customers with an incentive to implement more efficient lighting technologies that can produce verifiable savings. The Program promotes the installation of lighting technologies including but not limited to efficient fluorescent bulbs, LED- based bulbs, and lighting control systems.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Appendix 3M cont. – Description of Active DSM Programs

Non-Residential Window Film Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2014 – 2043
NC Duration:	2015 – 2043

Program Description:
This Program provides qualifying non-residential customers with an incentive to install solar reduction window film to lower their cooling bills and improve occupant comfort. Customers can receive rebates for installing qualified solar reduction window film in non-residential facilities based on the Solar Heat Gain Coefficient of window film installed.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Income and Age Qualifying Home Improvement Program

Target Class:	Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2015 – 2043
NC Duration:	2016 – 2043

Program Description:
This Program provides income and age-qualifying residential customers with energy assessments and direct install measures at no cost to the customer.

Program Marketing:
The Company markets this Program primarily through weatherization assistance providers and social services agencies.

Appendix 3M cont. – Description of Active DSM Programs

Residential Retail LED Lighting Program (NC only)
Target Class: Residential
NC Program Type: Energy Efficiency
NC Duration: 2017 – 2033

Program Description:
This Program provides residential customers in the Company's North Carolina service territory with an instant discount for qualifying LED light bulb purchases from a participating retailer. Qualifying bulbs will be those types that are commonly used, including general service (A-line) bulbs, specialty bulbs (candelabra base, globe, and reflector) and small fixtures meeting Energy Star and UL standards.

Program Marketing:
The instant rebate will be marketed using a combination of in-store point-of purchase, direct mail, social media, and online communications.

Small Business Improvement Program
Target Class: Non-Residential
VA Program Type: Energy Efficiency
NC Program Type: Energy Efficiency
VA Duration: 2016 – 2043
NC Duration: 2017 – 2043

Program Description:
This Program provides eligible small businesses an energy use assessment and tune-up or re-commissioning of electric heating and cooling systems, along with financial incentives for the installation of specific energy efficiency measures. Participating small businesses are required to meet certain connected load requirements.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company utilizes the contractor network to market the programs to customers as well.

Appendix 3M cont. – Description of Active DSM Programs

Non-Residential Prescriptive Program

Target Class:	Non-Residential
VA Program Type:	Energy Efficiency
NC Program Type:	Energy Efficiency
VA Duration:	2017 – 2043
NC Duration:	2018 – 2043

Program Description:
This Program will provide an incentive to eligible non-residential customers not otherwise eligible or who choose not to participate in the Company's Small Business Improvement Program. The Program would offer incentives for the installation of energy efficiency measures such as Refrigerator Evaporator Fans (Reach-in and Walk-in Coolers and Freezers), Commercial ENERGY STAR Appliances, Commercial Refrigeration, Commercial ENERGY STAR Ice Maker, Advanced Power Strip, Cooler/Freezer Strip Curtain, HVAC Tune-Up, Vending Machine Controls, Kitchen Fan Variable Speed Drives and Commercial Duct Testing and Sealing.

Program Marketing:
The Company uses a number of marketing activities to promote its approved DSM programs, including but not limited to: direct mail, bill inserts, web content, social media, and outreach events. Because these programs are implemented using a contractor network, customers will enroll in the program by contacting a participating contractor. The Company will utilize the contractor network to market the programs to customers as well.

Appendix 3N – Approved Programs Non-Coincidental Peak Savings for Plan E: Federal CO_2 Program (kW) (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	91,285	91,285	91,285	91,285	91,285	91,285	91,285	93,909	97,141	98,467	95,812	93,918	91,285	91,285	91,285	91,285
Residential Low Income Program	4,079	4,079	4,079	4,079	4,079	4,079	4,041	3,511	2,235	1,437	796	192	0	0	0	0
Residential Lighting Program	27,995	27,349	19,445	9,772	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	10,118	10,118	9,164	6,825	2,412	87	67	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	668	668	668	668	668	668	668	656	495	193	0	0	0	0	0	0
Non-Residential Energy Audit Program	5,656	5,654	5,029	3,155	702	335	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452	28,452
Non-Residential Distributed Generation Program	8,416	8,416	9,468	9,468	10,520	10,541	10,563	10,584	10,605	10,626	10,647	10,668	10,689	10,710	10,731	10,752
Residential Bundle Program	24,655	24,478	22,329	20,064	18,274	18,212	17,221	13,139	9,915	7,110	6,712	5,589	4,312	2,653	339	289
Residential Home Energy Check-Up Program	11,442	11,442	11,442	11,442	11,441	11,379	10,387	6,305	3,081	279	0	0	0	0	0	0
Residential Duct Sealing Program	353	353	353	353	353	353	353	353	353	353	353	353	353	351	339	289
Residential Heat Pump Tune Up Program	6,380	6,202	4,054	1,789	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	6,481	6,481	6,481	6,481	6,481	6,481	6,481	6,481	6,481	6,478	6,359	5,236	3,959	2,302	0	0
Non-Residential Window Film Program	34,093	49,232	51,712	54,241	56,821	58,162	58,602	59,034	59,450	59,853	60,245	60,630	61,009	61,384	61,755	62,126
Non-Residential Lighting Systems & Controls Program	42,316	43,473	44,654	45,858	47,085	48,022	55,450	55,411	53,050	48,316	48,483	48,647	48,808	48,967	49,125	49,282
Non-Residential Heating and Cooling Efficiency Program	34,729	47,946	50,101	52,295	54,529	55,698	56,093	56,481	56,856	57,218	57,571	57,917	58,257	58,595	59,466	59,262
Income and Age Qualifying Home Improvement Program	2,131	2,486	2,919	3,499	4,078	4,567	4,596	4,625	4,653	4,680	4,705	4,730	4,754	4,777	4,781	4,824
Residential Appliance Recycling Program	1,720	1,720	1,720	1,720	1,720	1,492	993	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	4,494	8,621	13,754	16,210	16,621	16,883	17,025	17,164	17,299	17,429	17,556	17,680	17,921	20,176	21,313	21,433
Residential Retail LED Lighting Program (NC only)	1,813	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977	1,977
Non-Residential Prescriptive Program	6,761	14,231	22,725	31,219	34,572	35,081	35,370	35,685	35,989	36,283	36,569	36,850	37,127	37,401	37,672	37,944
Total	329,382	370,187	379,482	380,788	373,796	375,541	382,404	380,628	378,118	372,040	369,524	367,249	364,590	366,378	366,896	367,626

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3O – Approved Programs Coincidental Peak Savings for Plan E: Federal CO_2 Program (kW) (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285	91,285
Residential Low Income Program	2,346	2,346	2,346	2,346	2,346	2,346	2,192	1,640	1,052	642	274	50	0	0	0	0
Residential Lighting Program	19,877	16,666	10,404	3,154	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	10,118	10,118	9,160	5,331	1,336	87	36	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	668	668	668	668	668	668	668	582	340	88	0	0	0	0	0	0
Non-Residential Energy Audit Program	5,287	5,285	4,748	2,360	659	225	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013	11,013
Non-Residential Distributed Generation Program	8,149	8,416	9,030	9,468	10,082	10,533	10,554	10,575	10,596	10,617	10,638	10,659	10,680	10,701	10,722	10,743
Residential Bundle Program	16,382	15,446	13,761	12,283	11,579	11,467	9,990	7,938	6,103	5,208	4,632	3,737	2,634	1,223	242	142
Residential Home Energy Check-Up Program	6,440	6,440	6,440	6,440	6,438	6,325	4,848	2,796	961	78	0	0	0	0	0	0
Residential Duct Sealing Program	266	266	266	266	266	266	266	266	266	266	266	266	265	261	242	142
Residential Heat Pump Tune Up Program	4,800	3,864	2,179	702	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	4,876	4,876	4,876	4,876	4,876	4,876	4,876	4,876	4,876	4,864	4,366	3,471	2,369	963	0	0
Non-Residential Window Film Program	23,381	35,622	37,413	39,239	41,101	42,070	42,382	42,680	42,968	43,232	43,498	43,776	44,049	44,320	44,588	44,856
Non-Residential Lighting Systems & Controls Program	25,640	30,603	31,450	32,313	33,192	33,639	33,770	33,899	34,023	34,144	34,261	34,376	34,489	34,601	34,712	34,823
Non-Residential Heating and Cooling Efficiency Program	27,747	40,863	42,700	44,570	46,474	47,470	47,807	48,138	48,457	48,766	49,066	49,361	49,651	49,939	50,223	50,508
Income and Age Qualifying Home Improvement Program	1,182	1,538	1,883	2,229	2,574	2,728	2,746	2,763	2,779	2,795	2,810	2,824	2,838	2,852	2,866	2,880
Residential Appliance Recycling Program	1,633	1,633	1,633	1,633	1,633	1,416	738	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	3,772	8,368	13,747	16,364	16,783	17,043	17,188	17,329	17,466	17,598	17,727	17,854	18,117	20,208	21,664	21,786
Residential Retail LED Lighting Program (NC only)	601	922	922	922	922	922	922	922	922	922	922	922	922	922	922	922
Non-Residential Prescriptive Program	4,658	12,524	20,390	28,256	31,956	32,433	32,731	33,023	33,306	33,579	33,844	34,105	34,362	34,616	34,867	35,119
Total	253,739	293,318	302,552	303,434	303,605	305,345	304,022	301,788	300,312	299,888	299,971	299,962	300,042	301,681	303,104	304,078

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3P – Approved Programs Energy Savings for Plan E: Federal CO_2 Program (MWh) (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Low Income Program	10,442	10,442	10,442	10,442	10,442	10,442	9,833	7,516	4,814	2,963	1,323	257	0	0	0	0
Residential Lighting Program	208,284	176,936	111,858	36,201	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	82,457	82,457	75,328	45,025	11,769	705	321	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	5,851	5,851	5,867	5,851	5,851	5,851	5,867	5,150	3,083	841	0	0	0	0	0	0
Non-Residential Energy Audit Program	36,155	36,143	32,687	16,938	4,614	1,636	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720
Non-Residential Distributed Generation Program	1	1,010	0	1	2	6	3	1	184	1	1	1	1	2	1	0
Residential Bundle Program	70,043	67,240	61,277	55,856	52,912	52,377	45,275	34,034	24,199	18,793	16,800	13,640	9,802	4,880	871	557
Residential Home Energy Check-Up Program	34,584	34,584	34,584	34,584	34,574	34,038	26,937	15,696	5,861	492	0	0	0	0	0	0
Residential Duct Sealing Program	947	947	947	947	947	947	947	947	947	947	947	947	946	932	871	557
Residential Heat Pump Tune Up Program	17,121	14,318	8,354	2,934	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,353	15,853	12,693	8,855	3,948	0	0
Non-Residential Window Film Program	25,660	39,033	40,999	43,005	45,051	46,110	46,460	46,805	47,138	47,463	47,778	48,083	48,384	48,681	48,975	49,270
Non-Residential Lighting Systems & Controls Program	159,339	193,288	198,635	204,087	209,646	212,664	213,495	214,311	215,099	215,860	216,601	217,328	218,044	218,753	219,453	220,155
Non-Residential Heating and Cooling Efficiency Program	70,367	108,956	113,859	118,852	123,935	126,804	127,705	128,590	129,445	130,270	131,074	131,863	132,639	133,408	134,168	134,928
Income and Age Qualifying Home Improvement Program	6,155	7,677	9,430	11,182	12,935	13,834	13,923	14,010	14,092	14,171	14,247	14,321	14,393	14,464	14,534	14,604
Residential Appliance Recycling Program	11,492	11,492	11,492	11,492	11,492	10,066	5,433	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	17,389	33,401	52,153	61,749	63,212	64,147	64,653	65,149	65,628	66,091	66,541	66,984	67,717	72,365	75,775	76,202
Residential Retail LED Lighting Program (NC only)	4,087	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557
Non-Residential Prescriptive Program	29,124	81,731	134,339	186,946	213,532	216,827	218,822	220,780	222,671	224,498	226,276	228,021	229,739	231,439	233,121	234,803
Total	804,567	929,936	932,643	881,906	839,671	835,746	826,066	810,623	800,632	795,228	794,919	794,774	794,995	798,268	801,175	804,797

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3Q – Approved Programs Penetrations for Plan E: Federal CO_2 Program (System-Level)

Programs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180	93,180
Residential Low Income Program	12,743	12,743	12,743	12,743	12,743	12,743	11,312	7,192	4,656	2,653	653	0	0	0	0	0
Residential Lighting Program	5,890,547	4,259,629	2,243,150	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	2,456	2,456	2,057	749	21	21	0	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	127	127	127	127	127	127	127	99	40	0	0	0	0	0	0	0
Non-Residential Energy Audit Program	1,740	1,739	1,437	305	154	17	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694
Non-Residential Distributed Generation Program	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10
Residential Bundle Program	151,592	126,324	98,903	78,621	75,993	74,424	54,722	39,866	24,610	22,975	19,680	15,987	11,172	5,004	3,336	1,153
Residential Home Energy Check-Up Program	52,963	52,963	52,963	52,963	52,932	51,363	31,661	16,805	1,549	0	0	0	0	0	0	0
Residential Duct Sealing Program	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,853	3,845	3,737	3,336	1,153
Residential Heat Pump Tune Up Program	75,568	50,300	22,879	2,597	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	19,208	19,208	19,208	19,208	19,208	19,208	19,208	19,208	19,208	19,122	15,827	12,134	7,327	1,267	0	0
Non-Residential Window Film Program	1,989,415	2,091,424	2,195,473	2,301,603	2,409,856	2,428,224	2,446,496	2,464,234	2,481,300	2,497,824	2,513,995	2,529,888	2,545,573	2,561,137	2,576,481	2,592,032
Non-Residential Lighting Systems & Controls Program	5,400	5,550	5,703	5,859	6,018	6,042	6,065	6,088	6,110	6,131	6,152	6,172	6,193	6,213	6,232	6,252
Non-Residential Heating and Cooling Efficiency Program	1,183	1,237	1,292	1,348	1,405	1,415	1,425	1,435	1,444	1,453	1,462	1,471	1,479	1,488	1,496	1,505
Income and Age Qualifying Home Improvement Program	17,399	21,899	26,399	30,899	35,399	35,628	35,856	36,074	36,280	36,478	36,670	36,857	37,041	37,223	37,401	37,583
Residential Appliance Recycling Program	14,072	14,072	14,072	14,072	14,072	10,866	3,131	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	1,797	2,787	3,934	4,017	4,102	4,131	4,160	4,188	4,215	4,242	4,267	4,292	4,317	4,342	4,366	4,391
Residential Retail LED Lighting Program (NC only)	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124	263,124
Non-Residential Prescriptive Program	460	916	1,372	1,828	1,870	1,887	1,905	1,921	1,937	1,953	1,968	1,983	1,998	2,013	2,027	2,042
Total	8,449,937	6,901,909	4,967,669	2,813,178	2,922,768	2,936,534	2,926,207	2,922,105	2,921,601	2,934,717	2,945,855	2,957,659	2,968,781	2,978,427	2,992,348	3,005,966

Note: Residential Bundle Program includes Residential Home Energy Check-Up Program, Residential Duct & Sealing Program, Residential Heat Pump Tune Up Program, and Residential Heat Pump Upgrade Program.

Appendix 3R – List of Transmission Lines under Construction

Line Terminals	Line Voltage (kV)	Line Capacity (MVA)	Target Date	Location
Line #47 Kings Dominion to Fredericksburg Rebuild	115	353	May-18	VA
Line #2183 Brambleton to Poland Road – New 230 kV Line and New 230kV Substation	230	1,047	May-18	VA
Line #2174 Vint Hill to Wheeler – New 230 kV Line	230	1,047	Jun-18	VA
Line #553 Cunningham to Elmont Rebuild	500	4,330	Jun-18	VA
Line #1009 Ridge Road to Chase City Rebuild	115	346	Jun-18	VA
Line #1020 Pantego to Trowbridge – New 115 kV Line	115	346	Jun-18	NC
Line #1015 Scotland Neck to South Justice Branch – New 115 kV Line	115	346	Sep-18	NC
Line #2086 Remington Combustion Turbine to Warrenton Rebuild	230	1,047	Oct-18	VA
Line #2161 Wheeler to Gainesville Uprate	230	1,047	Dec-18	VA
Line #54 Carolina to Woodland Reconductor	115	174	Dec-18	NC
Line #171 Chase City to Boydton Plank Road	115	393	Jun-19	VA
Line #90 Carolina to Kerr Dam Rebuild	115	346	Dec-19	VA/NC
Line #4 Bremo to Cartersville Uprate	115	151	May-18	VA
Line #48 Sewells Point to Thole Street and Line #107 Oakwood to Sewells Point Partial Rebuild	115	317 (#48) 353 (#107)	Dec-18	VA
Line #585 Carsons to Rogers Road Rebuild	500	4,330	Dec-18	VA
Line #34 Skiffes Creek to Yorktown and Line #61 Whealton to Yorktown Partial Rebuild	115	353 (#34)	May-19	VA
Line #582 Surry to Skiffes Creek – New 500 kV Line	500	4,330	May-19	VA
Line #2138 Skiffes Creek to Whealton – New 230 kV Line	230	1,047	May-19	VA
Line #159 Acca to Hermitage Reconductor	115	353	May-19	VA
Line #534 Cunningham to Dooms Rebuild	500	4,330	Jun-19	VA
Line #171 Chase City to Boydton Plank Road Rebuild	115	393	Jun-19	VA
Line #82 Everetts to Leggetts Crossroads Delivery Point Rebuild	115	353	Dec-19	NC
Line #130 Clubhouse to Carolina Rebuild	115	394	Dec-19	VA/NC

Appendix 4A – ICF Commodity Price Forecasts for Virginia Electric and Power Company

Fall 2017 Forecast

NOTICE PROVISIONS FOR AUTHORIZED THIRD PARTY USERS.

This report and information and statements herein are based in whole or in part on information obtained from various sources. ICF makes no assurances as to the accuracy of any such information or any conclusions based thereon. ICF is not responsible for typographical, pictorial or other editorial errors. The report is provided AS IS.

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ICF Federal CO_2 Commodity Price Forecast (Nominal $)

	Fuel Price					Power and REC Prices				Emission Prices			
Year	Henry Hub Natural Gas ($/MMBtu)	DOM Zone Delivered Natural Gas ($/MMBtu)	CAPP CSX: 12,500 1%S FOB ($/MMBtu)	No. 2 Oil ($/MMBtu)	1% No.6 Oil ($/MMBtu)	PJM-DOM On Peak ($/MWh)	PJM-DOM Off-Peak ($/MWh)	PJM Tier 1 REC Prices ($/MWh)	RTO Capacity Prices ($/kW-yr)	CSAPR SO_2 ($/ton)	CSAPR Ozone NO_x ($/ton)	CSAPR Annual NO_x ($/ton)	CO_2 ($/ton)
2018	2.85	2.86	2.52	14.36	9.12	42.25	30.55	5.25	58.12	2.56	150.00	2.56	0.00
2019	2.87	2.87	2.42	13.73	8.61	38.33	29.11	5.25	46.35	2.65	192.19	2.67	0.00
2020	3.31	3.24	2.34	13.36	8.46	37.16	29.76	5.03	31.50	2.90	604.96	3.08	0.00
2021	3.64	3.49	2.33	14.14	8.91	35.97	29.90	4.87	30.63	3.08	867.79	3.36	0.00
2022	3.78	3.54	2.39	15.52	9.88	36.53	30.28	5.19	35.57	3.14	925.09	3.43	0.00
2023	3.91	3.66	2.45	16.53	10.58	37.69	31.29	5.53	40.42	3.20	985.90	3.49	0.00
2024	4.05	3.66	2.51	17.18	11.02	37.70	31.39	5.89	45.43	3.26	1,050.72	3.56	0.00
2025	4.20	3.78	2.57	17.98	11.57	38.96	32.33	6.28	50.62	3.32	1,119.63	3.62	0.00
2026	4.33	4.00	2.63	18.68	12.05	40.78	34.02	6.69	55.98	3.38	913.36	3.69	0.35
2027	4.47	4.19	2.69	19.34	12.50	42.24	35.45	7.13	61.54	3.45	745.32	3.76	0.56
2028	4.61	4.21	2.76	19.98	12.93	42.32	35.53	7.60	67.30	3.51	608.48	3.83	1.83
2029	4.75	4.45	2.83	20.73	13.44	44.52	37.35	8.10	74.11	3.58	496.95	3.91	2.16
2030	4.90	4.51	2.89	21.35	13.86	44.62	37.67	8.63	81.74	3.65	3.98	3.98	3.70
2031	5.03	4.62	2.96	22.21	14.45	45.88	38.90	9.20	86.66	3.72	4.06	4.06	5.04
2032	5.16	4.66	3.02	23.09	15.06	46.45	39.61	9.80	89.58	3.79	4.13	4.13	6.53
2033	5.30	5.01	3.09	24.02	15.70	50.25	42.91	10.44	92.57	3.86	4.21	4.21	8.20

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices for all commodities except capacity prices. 2021 and beyond are forecast prices. Capacity prices reflect PJM RPM auction clearing prices through delivery year 2020/2021, forecast thereafter. CO_2 prices reflect the price in Virginia. Refer to Sections 4.4.1 and 4.4.2 for additional details.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Natural Gas

	DOM Zone Natural Gas Price (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.86	2.86	2.86
2019	2.87	2.87	2.87
2020	3.24	3.33	3.33
2021	3.49	3.61	3.61
2022	3.54	3.65	3.65
2023	3.66	3.72	3.76
2024	3.66	3.70	3.76
2025	3.78	3.81	3.87
2026	4.00	4.01	4.06
2027	4.19	4.17	4.21
2028	4.21	3.99	4.19
2029	4.45	4.23	4.39
2030	4.51	4.17	4.40
2031	4.62	4.24	4.48
2032	4.66	4.16	4.47
2033	5.01	4.58	4.79

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Natural Gas

	Henry Hub Natural Gas Price (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.85	2.85	2.85
2019	2.87	2.88	2.88
2020	3.31	3.40	3.39
2021	3.64	3.76	3.76
2022	3.78	3.89	3.89
2023	3.91	4.02	4.02
2024	4.05	4.15	4.15
2025	4.20	4.29	4.29
2026	4.33	4.38	4.38
2027	4.47	4.48	4.48
2028	4.61	4.59	4.59
2029	4.75	4.69	4.69
2030	4.90	4.80	4.80
2031	5.03	4.89	4.89
2032	5.16	4.99	4.99
2033	5.30	5.08	5.09

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Coal: FOB

	CAPP 12,500 1% S Coal (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.52	2.52	2.52
2019	2.42	2.42	2.42
2020	2.34	2.35	2.35
2021	2.33	2.34	2.34
2022	2.39	2.40	2.40
2023	2.45	2.46	2.46
2024	2.51	2.52	2.52
2025	2.57	2.58	2.58
2026	2.63	2.64	2.64
2027	2.69	2.70	2.70
2028	2.76	2.76	2.76
2029	2.83	2.83	2.83
2030	2.89	2.89	2.89
2031	2.96	2.96	2.96
2032	3.02	3.03	3.03
2033	3.09	3.09	3.09

Note: The 2018 – 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Oil

	No. 2 Oil (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	14.36	14.36	14.36
2019	13.73	13.73	13.73
2020	13.36	13.36	13.36
2021	14.14	14.14	14.14
2022	15.52	15.52	15.52
2023	16.53	16.53	16.53
2024	17.18	17.18	17.18
2025	17.98	17.98	17.98
2026	18.68	18.68	18.68
2027	19.34	19.34	19.34
2028	19.98	19.98	19.98
2029	20.73	20.73	20.73
2030	21.35	21.35	21.35
2031	22.21	22.21	22.21
2032	23.09	23.09	23.09
2033	24.02	24.02	24.02

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Oil

	1% No. 6 Oil (Nominal $/MMBtu)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	9.12	9.12	9.12
2019	8.61	8.61	8.61
2020	8.46	8.46	8.46
2021	8.91	8.90	8.90
2022	9.88	9.88	9.88
2023	10.58	10.58	10.58
2024	11.02	11.02	11.02
2025	11.57	11.57	11.57
2026	12.05	12.05	12.05
2027	12.50	12.50	12.50
2028	12.93	12.93	12.93
2029	13.44	13.44	13.44
2030	13.86	13.86	13.86
2031	14.45	14.45	14.45
2032	15.06	15.06	15.06
2033	15.70	15.70	15.70

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; On-Peak Power Price

	Dom Zone Power On Peak (Nominal $/MWh)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	42.25	42.25	42.25
2019	38.33	38.41	38.38
2020	37.16	38.33	38.05
2021	35.97	37.52	37.07
2022	36.53	38.06	37.54
2023	37.69	38.73	38.56
2024	37.70	38.65	38.45
2025	38.96	39.90	39.56
2026	40.78	41.76	40.92
2027	42.24	43.20	41.90
2028	42.32	41.42	41.38
2029	44.52	44.08	43.09
2030	44.62	43.34	42.67
2031	45.88	43.86	43.16
2032	46.45	42.63	42.91
2033	50.25	46.88	45.87

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; Off-Peak Power Price

	Dom Zone Power Off Peak (Nominal $/MWh)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	30.55	30.55	30.55
2019	29.11	29.16	29.14
2020	29.76	30.62	30.43
2021	29.90	31.11	30.78
2022	30.28	31.50	31.13
2023	31.29	32.19	32.09
2024	31.39	32.23	32.13
2025	32.33	33.23	33.01
2026	34.02	34.89	34.29
2027	35.45	36.24	35.28
2028	35.53	34.74	34.82
2029	37.35	36.83	36.18
2030	37.67	36.38	36.01
2031	38.90	36.88	36.49
2032	39.61	36.04	36.40
2033	42.91	39.55	38.87

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; PJM Tier 1 Renewable Energy Certificates

	PJM Tier 1 REC Prices (Nominal $/MWh)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	5.25	5.25	5.25
2019	5.25	5.32	5.33
2020	5.03	5.97	6.03
2021	4.87	6.37	6.46
2022	5.19	6.79	6.88
2023	5.53	7.23	7.34
2024	5.89	7.70	7.82
2025	6.28	8.21	8.33
2026	6.69	8.75	8.87
2027	7.13	9.32	9.46
2028	7.60	9.94	10.08
2029	8.10	10.59	10.75
2030	8.63	11.29	11.45
2031	9.20	12.03	12.20
2032	9.80	12.81	13.00
2033	10.44	13.65	13.85

Note: The 2018 - 2020 prices are a blend of futures/forwards and forecast prices. 2021 and beyond are forecast prices.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; PJM RTO Capacity

	RTO Capacity Prices (Nominal $/kW yr)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	58.12	58.12	58.12
2019	46.35	46.35	46.35
2020	31.50	31.50	31.50
2021	30.63	30.78	30.83
2022	35.57	35.99	36.11
2023	40.42	41.11	41.31
2024	45.43	46.41	46.69
2025	50.62	51.89	52.25
2026	55.98	57.56	58.01
2027	61.54	63.44	63.98
2028	67.30	69.53	70.17
2029	74.11	76.14	76.84
2030	81.74	83.18	83.93
2031	86.66	87.75	88.47
2032	89.58	90.51	91.13
2033	92.57	93.34	93.86

Note: PJM RPM auction clearing prices through delivery year 2020/21, forecast thereafter.

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; SO_2 Emission Allowances

	CSAPR SO_2 Prices (Nominal $/ton)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	2.56	2.56	2.56
2019	2.65	2.65	2.65
2020	2.90	2.90	2.90
2021	3.08	3.08	3.08
2022	3.14	3.14	3.14
2023	3.20	3.20	3.20
2024	3.26	3.26	3.26
2025	3.32	3.32	3.32
2026	3.38	3.38	3.38
2027	3.45	3.45	3.45
2028	3.51	3.51	3.51
2029	3.58	3.58	3.58
2030	3.65	3.65	3.65
2031	3.72	3.72	3.72
2032	3.79	3.79	3.79
2033	3.86	3.86	3.86

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; NO_x Emission Allowances

	CSAPR Ozone NOx Prices (Nominal $/ton)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	150.00	150.00	150.00
2019	192.19	192.19	192.19
2020	604.96	604.96	604.96
2021	867.79	867.79	867.79
2022	925.09	925.09	925.09
2023	985.90	985.90	985.90
2024	1,050.72	1,050.72	1,050.72
2025	1,119.63	1,119.63	1,119.63
2026	913.36	913.36	913.36
2027	745.32	745.32	745.32
2028	608.48	608.48	608.48
2029	496.95	496.95	496.95
2030	3.98	3.98	3.98
2031	4.06	4.06	4.06
2032	4.13	4.13	4.13
2033	4.21	4.21	4.21

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; NO_x Emission Allowances

	CSAPR Annual NOx Prices (Nominal $/ton)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	6.14	0.00
2021	0.00	6.47	0.00
2022	0.00	6.80	0.00
2023	0.00	7.14	0.00
2024	0.00	7.50	0.00
2025	0.00	7.87	0.00
2026	0.35	8.28	0.00
2027	0.56	8.72	0.00
2028	1.83	9.18	0.00
2029	2.16	9.66	0.00
2030	3.70	10.17	0.00
2031	5.04	10.71	0.00
2032	6.53	11.29	0.00
2033	8.20	11.89	0.00

ICF Federal CO_2 Commodity Forecast, Virginia RGGI Commodity Forecast, and No CO_2 Tax Commodity Forecast; CO_2

	CO_2 Prices (Nominal $/ton)		
Year	Federal CO_2 Commodity Forecast	Virginia RGGI Commodity Forecast	No CO_2 Tax Commodity Forecast
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	6.14	0.00
2021	0.00	6.47	0.00
2022	0.00	6.80	0.00
2023	0.00	7.14	0.00
2024	0.00	7.50	0.00
2025	0.00	7.87	0.00
2026	0.35	8.28	0.00
2027	0.56	8.72	0.00
2028	1.83	9.18	0.00
2029	2.16	9.66	0.00
2030	3.70	10.17	0.00
2031	5.04	10.71	0.00
2032	6.53	11.29	0.00
2033	8.20	11.89	0.00

Note: The CO_2 prices are reflective of the price in Virginia.

Appendix 4B – Delivered Fuel Data for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 18**

FUEL DATA

	(ACTUAL)				(PROJECTED)														
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
I. Delivered Fuel Price ($/mmBtu)(1)																			
a. Nuclear	0.67	0.70	0.70	0.64	0.64	0.63	0.61	0.61	0.60	0.61	0.61	0.63	0.64	0.65	0.66	0.66	0.67	0.68	0.69
b. Coal	2.87	2.61	2.70	2.10	2.18	2.24	2.30	2.36	2.42	2.47	2.53	2.59	2.66	2.72	2.79	2.85	2.92	2.99	3.06
c. Heavy Fuel Oil	7.78	7.28	6.34	6.60	7.04	8.23	9.06	9.58	10.04	10.43	10.80	11.21	11.69	12.14	12.58	13.09	13.52	14.11	14.73
d. Light Fuel Oil(2)	14.54	10.63	11.73	11.35	11.97	13.22	14.26	15.02	15.69	16.27	16.81	17.42	18.12	18.78	19.43	20.18	20.81	21.68	22.57
e. Natural Gas	4.11	2.37	3.50	3.28	3.30	3.41	3.49	3.54	3.66	3.66	3.77	4.00	4.19	4.21	4.45	4.51	4.62	4.66	5.01
f. Renewable(3)	3.16	3.17	3.00	2.44	2.79	2.83	2.87	2.92	2.93	3.00	3.03	3.07	3.17	3.22	3.30	3.39	3.47	3.57	3.67
II. Primary Fuel Expenses (cents/kWh)(4)																			
a. Nuclear	0.69	0.72	0.72	0.68	0.68	0.66	0.64	0.63	0.63	0.64	0.64	0.66	0.67	0.67	0.68	0.69	0.70	0.71	0.72
b. Coal	3.13	3.09	2.88	2.46	2.35	2.36	2.40	2.47	2.54	2.60	2.68	2.75	2.80	2.86	2.93	3.00	3.08	3.16	3.24
c. Heavy Fuel Oil	12.25	8.56	7.60	10.10	9.59	9.36	9.43	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Light Fuel Oil(2)	11.62	6.80	16.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
e. Natural Gas	3.03	2.18	2.64	2.01	2.00	2.08	2.09	2.08	2.09	2.05	2.10	2.37	2.48	2.53	2.61	2.70	2.77	2.85	2.94
f. Renewable(3)	4.93	4.64	4.25	3.05	3.11	3.16	3.21	3.25	3.28	3.38	3.39	3.45	3.58	3.62	3.68	3.82	3.91	4.02	4.12
g. NUG(5)	3.21	2.98	5.28	6.99	2.24	2.86	2.92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
i. Economy Energy Purchases(6)	4.56	15.62	3.36	2.50	2.52	2.50	2.46	2.50	2.56	2.56	2.71	2.93	2.89	2.98	3.17	3.21	3.38	3.56	3.84
j. Capacity Purchases ($/kW-Year)	48.12	49.21	52.64	58.12	46.35	31.50	30.78	35.99	41.11	46.41	51.89	57.56	63.44	69.53	76.14	83.18	87.75	90.51	93.34

(1) Delivered fuel price for Central Appalachian ("CAPP") CSX (12,500, 1% FOB), No. 2 Oil, No. 6 Oil, DOM Zone Delivered Natural Gas are used to represent Coal, Heavy Fuel, Light Fuel Oil and Natural Gas respectively.

(2) Light fuel oil is used for reliability only at dual-fuel facilities.

(3) Reflects biomass units only.

(4) Primary Fuel Expenses for Nuclear, Coal, Heavy Fuel Oil, Natural Gas and Renewable are based on North Anna 1, Chesterfield 6, Yorktown 3, Possum Point 6, Pittsylvania, respectively.

(5) Average of NUGs Fuel Expenses.

(6) Average cost of Market Energy Purchases.

Appendix 5A - Tabular Results of Busbar

	Capacity Factor (%)										
$/kW Year	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2X1 CC	$ 197	$ 231	$ 266	$ 301	$ 336	$ 370	$ 405	$ 440	$ 475	$ 509	$ 544
1X1 CC	$ 257	$ 293	$ 330	$ 367	$ 403	$ 440	$ 476	$ 513	$ 550	$ 586	$ 623
CT	$ 58	$ 123	$ 188	$ 252	$ 317	$ 382	$ 447	$ 512	$ 576	$ 641	$ 706
Aero CT	$ 198	$ 249	$ 301	$ 352	$ 403	$ 454	$ 506	$ 557	$ 608	$ 659	$ 711
Solar & Aero CT	$ 309	$ 349	$ 388	$ 427	$ 467	$ 506	$ 545	$ 584	$ 624	$ 663	$ 702
Nuclear	$ 1,048	$ 1,058	$ 1,068	$ 1,078	$ 1,088	$ 1,098	$ 1,108	$ 1,118	$ 1,128	$ 1,139	$ 1,149
Biomass	$ 968	$ 1,045	$ 1,122	$ 1,198	$ 1,275	$ 1,352	$ 1,429	$ 1,505	$ 1,582	$ 1,659	$ 1,735
Fuel Cell	$ 1,313	$ 1,341	$ 1,370	$ 1,399	$ 1,427	$ 1,456	$ 1,485	$ 1,514	$ 1,542	$ 1,571	$ 1,600
SCPC w/ CCS	$ 636	$ 780	$ 925	$ 1,069	$ 1,213	$ 1,357	$ 1,502	$ 1,646	$ 1,790	$ 1,935	$ 2,079
IGCC w/ CCS	$ 1,282	$ 1,416	$ 1,549	$ 1,682	$ 1,815	$ 1,949	$ 2,082	$ 2,215	$ 2,349	$ 2,482	$ 2,615
Solar				$ 103							
Onshore Wind					$ 269						
Offshore Wind					$ 443						
CVOW					$ 2,810						

(1) CVOW and Offshore Wind both have a capacity factor of 42%.
(2) Onshore Wind has a capacity factor of 37%.
(3) Solar PV has a capacity factor of 26%.

Appendix 5B - Busbar Assumptions

Nominal $	Heat Rate	Variable Cost[1]	Fixed Cost[3]	Book Life	2017 Real $[2]
	MMBtu/MWh	$/MWh	$/kW Year	Years	$/kW
2X1 CC	6.59	40	197	36	1,233
1X1 CC	6.63	42	257	36	1,668
CT	10.07	74	58	36	476
Aero CT	9.32	59	198	36	1,680
Solar & Aero CT	9.32	58	235	35 (Solar) / 36 (CT)	3,366
Nuclear	10.50	12	1,048	60	9,133
Biomass	13.00	88	968	40	6,698
Fuel Cell	8.54	33	1,313	15	5,880
SCPC w/ CCS	11.06	165	636	55	5,366
IGCC w/ CCS	10.88	152	1,282	40	10,839
Solar	-	(10)	128	35	1,436
Onshore Wind	-	(9)	301	25	2,112
Offshore Wind	-	(9)	476	30	4,021
CVOW	-	(9)	2,841	25	25,838

(1) Variable cost for biomass, solar, solar & aero, onshore wind, offshore wind, and CVOW includes value for RECs.

(2) Values in this column represent overnight installed costs.

(4) Fixed costs include investment tax credits and gas firm transportation expenses.

Appendix 5C – Planned Generation under Development

Company Name: Virginia Electric and Power Company **Schedule 15c**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[2]	MW Summer	MW Nameplate
Under Development[1]						
US-3 Solar 1	VA	Intermittent	Solar	2020	33	142
US-3 Solar 2	VA	Intermittent	Solar	2021	22	98
CVOW	VA	Intermittent	Wind	2021	2	12[3]
Surry Unit 1 Nuclear Extension	VA	Baseload	Nuclear	2032	838	875
Surry Unit 2 Nuclear Extension	VA	Baseload	Nuclear	2033	838	875
North Anna Unit 1 Nuclear Extension	VA	Baseload	Nuclear	2038	838	868
North Anna Unit 2 Nuclear Extension	VA	Baseload	Nuclear	2040	834	863

(1) Includes the additional resources under development in the Alternative Plans.
(2) Estimated Commercial Operation Date.
(3) Accounts for line losses.

Appendix 5D – Standard DSM Test Descriptions

Participant Test

The Participant test is the measure of the quantifiable benefits and costs to program participants due to enrollment in a program. This test indicates whether the program or measure is economically attractive to the customer enrolled in the program. Benefits include the participant's retail bill savings over time plus any incentives offered by the utility, while costs include only the participant's costs. A result of 1.0 or higher indicates that a program is beneficial for the participant.

Utility Cost Test

The Utility Cost test compares the cost to the utility to implement a program to the cost that is expected to be avoided as a result of the program implementation. The Utility Cost test measures the net costs and benefits of a DSM program as a resource option, based on the costs and benefits incurred by the utility including incentive costs and excluding any net costs incurred by the participant. The Utility Cost test ignores participant costs, meaning that a measure could pass the Utility Cost test, but may not be cost-effective from a more comprehensive perspective. A result of 1.0 or higher indicates that a program is beneficial for the utility.

Total Resource Cost Test

The TRC test compares the total costs and benefits to the utility and participants, relative to the costs to the utility and participants. It can also be viewed as a combination of the Participant and Utility Cost tests, measuring the impacts to the utility and all program participants as if they were treated as one group. Additionally, this test considers customer incentives as a pass-through benefit to customers and, therefore, does not include customer incentives. If a program passes the TRC test, then it is a viable program absent any equity issues associated with non-participants. A result of 1.0 or higher indicates that a program is beneficial for both participants and the utility.

Ratepayer Impact Measure Test

The RIM test considers equity issues related to programs. This test determines the impact the DSM program will have on non-participants and measures what happens to customer bills or rates due to changes in utility revenues and operating costs attributed to the program. A score on the RIM test of greater than 1.0 indicates the program is beneficial for both participants and non-participants, because it should have the effect of lowering bills or rates even for customers not participating in the program. Conversely, a score on the RIM test of less than 1.0 indicates the program is not as beneficial because the costs to implement the program exceed the benefits shared by all customers, including non-participants.

Appendix 5E – DSM Programs Energy Savings for Plan E: Federal CO_2 Program (MWh) (System-Level)

Company Name: Virginia Electric and Power Company

Schedule 12

				ACTUAL - MWh			(PROJECTED - MWh)															
Program Name	Date (2)	Life/ Duration (3)	Size kW (4)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Air Conditioner Cycling Program	2010	2033	91,285	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-total			91,285	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Residential Distributed Generation Program	2010	2033	10,743				1	1,010	0	1	2	6	3	1	184	1	1	1	1	2	1	0
Standby Generation (Pricing Tariffs) (5)	1987	2033	1,482	342	274	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
Sub-total			12,226	342	274	139	140	1,149	139	140	141	145	142	140	323	140	140	140	140	140	140	139
Residential Low Income Program	2010	2029	0	6,536	6,682	6,682	10,442	10,442	10,442	10,442	10,442	10,442	9,833	7,516	4,814	2,963	1,323	257	0	0	0	0
Residential Lighting Program	2010	2021	0	228,892	228,892	228,892	208,284	176,936	111,858	36,201	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Lighting Program	2010	2024	0	73,417	73,417	73,417	82,457	82,457	75,328	45,025	11,769	705	321	0	0	0	0	0	0	0	0	0
Commercial HVAC Upgrade	2010	2027	0	5,936	5,936	5,936	5,851	5,851	5,867	5,851	5,851	5,851	5,867	5,150	3,083	841	0	0	0	0	0	0
Non-Residential Energy Audit Program	2010	2023	0	33,297	35,623	40,510	36,155	36,143	32,687	16,938	4,614	1,636	0	0	0	0	0	0	0	0	0	0
Non-Residential Duct Testing and Sealing Program	2012	2033	11,013	36,674	56,854	71,873	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720	67,720
Residential Bundle Program	2010 (6)	2033	142	45,264	59,890	67,819	70,043	67,240	61,277	55,856	52,912	52,377	45,275	34,034	24,199	18,793	16,800	13,640	9,802	4,880	871	557
Residential Home Energy Check-Up Program	2012	2027	0	19,706	28,450	33,381	34,584	34,584	34,584	34,584	34,574	34,038	26,937	15,696	5,861	492	0	0	0	0	0	0
Residential Duct Sealing Program	2012	2033	142	451	759	895	947	947	947	947	947	947	947	947	947	947	947	947	946	932	871	557
Residential Heat Pump Tune Up Program	2012	2021	0	13,140	17,656	19,775	17,121	14,318	8,354	2,934	0	0	0	0	0	0	0	0	0	0	0	0
Residential Heat Pump Upgrade Program	2012	2031	0	11,966	13,024	13,769	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,391	17,353	15,853	12,693	8,855	3,948	0	0
Non-Residential Window Film Program	2014	2033	44,856	2,765	3,618	4,426	25,660	39,033	40,999	43,005	45,051	46,110	46,460	46,805	47,138	47,463	47,778	48,083	48,384	48,681	48,975	49,270
Non-Residential Lighting Systems & Controls Program	2014	2033	34,823	21,142	63,983	115,051	159,339	193,288	198,635	204,087	209,646	212,664	213,495	214,311	215,099	215,860	216,601	217,328	218,044	218,753	219,453	220,155
Non-Residential Heating and Cooling Efficiency Program	2014	2033	50,508	4,965	13,607	22,346	70,367	108,956	113,859	118,852	123,935	126,804	127,705	128,590	129,445	130,270	131,074	131,863	132,639	133,408	134,168	134,928
Income and Age Qualifying Home Improvement Program	2015	2033	2,880	112	1,991	4,915	6,155	7,677	9,430	11,182	12,935	13,834	13,923	14,010	14,092	14,171	14,247	14,321	14,393	14,464	14,534	14,604
Residential Appliance Recycling Program	2015	2024	0	659	5,489	10,471	11,492	11,492	11,492	11,492	11,492	10,066	5,433	0	0	0	0	0	0	0	0	0
Small Business Improvement Program	2016	2033	21,786	0	68	7,442	17,389	33,401	52,153	61,749	63,212	64,147	64,653	65,149	65,628	66,091	66,541	66,984	67,717	72,365	75,775	76,202
Residential Retail LED Lighting Program (NC only)	2017	2033	922	0	0	512	4,087	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557	6,557
Non-Residential Prescriptive Program	2017	2033	35,119	0	0	0	29,124	81,731	134,339	186,946	213,532	216,827	218,822	220,780	222,671	224,498	226,276	228,021	229,739	231,439	233,121	234,803
Sub-total			202,049	459,660	556,048	660,292	804,565	928,926	932,643	881,905	839,669	835,740	826,063	810,621	800,448	795,227	794,918	794,773	794,994	798,266	801,174	804,797
Total Demand-Side Management			305,560	460,002	556,322	660,431	804,705	930,075	932,782	882,045	839,810	835,885	826,205	810,762	800,771	795,367	795,058	794,913	795,134	798,407	801,314	804,936

(1) The Program types have been categorized by the Virginia definitions of peak shaving, energy efficiency, and demand response.

(2) Implementation date.

(3) State expected life of facility or duration of purchase contract. The Company used Program Life (Years).

(4) The MWs reflected as of 2033.

(5) Reductions available during on-peak hours.

(6) Residential Bundle is comprised of the Residential Home Energy Check-Up Program, Residential Duct Testing & Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program.

Confidential Information Redacted

Appendix 5F – Cost Estimates for Nuclear License Extensions

	Capital Cost
North Anna Units 1 & 2	[redacted]
Surry Units 1 & 2	[redacted]

Appendix 6A – Renewable Resources for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 11**

RENEWABLE RESOURCE GENERATION (GWh)

						(ACTUAL)			(PROJECTED)															
Resource Type(1)	**Unit Name**	**C.O.D.(2)**	**Build/Purchase/ Convert(3)**	**Life/ Duration(4)**	**Size MW(5)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Hydro																								
	Gaston Hydro	Feb-63	Build	60	220	316	408	271	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258	258
	North Anna Hydro	Dec-87	Build	60	1	4	4	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Roanoke Rapids Hydro	Sep-55	Build	60	95	288	355	211	253	253	254	253	253	253	254	253	253	253	254	253	253	253	254	253
Sub-total					318	617	775	484	513	513	514	513	513	513	514	513	513	513	514	513	513	513	514	513
Solar																								
	Solar Partnership Program	2013-2017	Build	20	7	2.3	7	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Existing NC Solar NUGs	2014-2022	Purchase	20	660	161	441	634	1,201	1,380	1,450	1,438	1,431	1,424	1,421	1,410	1,403	1,396	1,393	1,382	1,375	1,368	1,355	1,344
	Existing VA Solar NUGs	2016-2017	Purchase	20	100	-	-	-	45	62	62	62	61	61	61	60	60	60	59	59	59	59	58	58
	US-3 Solar 1	2020	Build	35	142				-	-	355	352	351	349	348	345	344	342	341	339	337	335	334	332
	US-3 Solar 2	2021	Build	35	98				-	-	-	233	232	231	230	228	227	226	226	224	223	222	221	219
	Whitehouse Solar	Dec-2016	Build	35	20	-	1	35	44	43	43	43	43	43	42	42	42	42	42	41	41	41	41	40
	Scott Solar	Dec-2016	Build	35	17	-	1	31	37	37	37	37	37	37	36	36	36	36	36	35	35	35	35	35
	Woodland Solar	Dec-2016	Build	35	19	-	1	30	43	42	42	42	42	41	41	41	41	41	41	40	40	40	40	39
	Generic Solar PV	2019-2032	Build	35	5,760	-	-	-	-	-	715	1,604	2,673	3,742	4,647	5,702	6,771	7,841	8,936	9,801	10,514	10,692	11,795	12,830
Sub-total					6,823	164	449.8	737	1,378	1,574	2,713	3,820	4,878	5,936	6,835	7,874	8,933	9,991	11,081	11,930	12,632	12,800	13,888	14,907
Biomass	**Unit Name**																							
	Pittsylvania	Jun-94	Purchase	60	83	267	146	109	394	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Virginia City Hybrid Energy Center (6)	Apr-12	Build	60	61	100	236	204	240	259	332	339	353	343	316	327	351	342	321	318	309	301	290	297
	Altavista	Feb-92	Convert	30	51	269	283	276	336	336	335	329	334	51	52	58	71	78	73	81	81	92	98	131
	Southampton	Mar-92	Convert	30	51	290	30	28	272	235	247	225	242	27	28	29	30	37	31	39	37	43	48	71
	Hopewell	Jul-92	Convert	30	51	263	306	295	307	290	303	292	299	41	39	39	45	55	51	55	61	72	73	100
Sub-total					297	1,189	1,000	912	1,551	1,120	1,217	1,184	1,227	463	435	452	498	512	476	494	488	509	509	599
Wind																								
	CVOW	Jan-21	Build	20	12	-	-		-	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44
Sub-total					12	-	-		-	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44
Total Renewables					7,450	1,969	2,225	2,133	3,441	3,207	4,444	5,561	6,662	6,956	7,829	8,883	9,987	11,059	12,115	12,980	13,677	13,865	14,955	16,062

(1) Per definition of § 56-576 of the Code of Virginia.

(2) Commercial Operation Date.

(3) Company built, purchased or converted.

(4) Expected life of facility or duration of purchase contract.

(5) Net Summer Capacity for Biomass and Hydro, Nameplate for Solar and Wind.

(6) Dual fired coal & biomass reaching 61 MW in 2023.

.

Appendix 6B – Potential Supply-Side Resources for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 15b**

UNIT PERFORMANCE DATA

Potential Supply-Side Resources (MW)

Unit Name	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer [2]	MW Nameplate
Solar 2020	Intermittent	Solar	2020	73	320
US-3 Solar 1	Intermittent	Solar	2020	33	142
Solar 2021	Intermittent	Solar	2021	91	400
US-3 Solar 2	Intermittent	Solar	2021	22	98
CVOW	Intermittent	Wind	2021	2	12
Solar 2022	Intermittent	Solar	2022	110	480
Generic CT	Peak	Natural Gas	2022	458	458
Solar 2023	Intermittent	Solar	2023	110	480
Generic CT	Peak	Natural Gas	2023	458	458
Solar 2024	Intermittent	Solar	2024	91	400
Generic CT	Peak	Natural Gas	2024	458	458
Solar 2025	Intermittent	Solar	2025	110	480
Generic CT	Peak	Natural Gas	2025	458	458
Solar 2026	Intermittent	Solar	2026	110	480
Generic CT	Peak	Natural Gas	2026	458	458
Solar 2027	Intermittent	Solar	2027	110	480
Solar 2028	Intermittent	Solar	2028	110	480
Solar 2029	Intermittent	Solar	2029	91	400
Generic CT	Peak	Natural Gas	2029	458	458
Solar 2030	Intermittent	Solar	2030	73	320
Generic CT	Peak	Natural Gas	2030	458	458
Solar 2031	Intermittent	Solar	2031	18	80
Generic CT	Peak	Natural Gas	2031	458	458
Solar 2032	Intermittent	Solar	2032	110	480
Solar 2033	Intermittent	Solar	2033	110	480

(1) Estimated Commercial Operation Date.
(2) Summer MWs represent the firm capacity of each unit.

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Appendix 6C – Summer Capacity Position for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 16**

UTILITY CAPACITY POSITION (MW)

	(ACTUAL)			(PROJECTED)															
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Existing Capacity																			
Conventional	18,928	18,933	18,956	17,736	17,663	17,609	16,745	15,948	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945	15,945
Renewable	553	553	553	529	523	529	535	542	545	545	545	545	545	545	545	544	544	544	544
Total Existing Capacity	19,481	19,486	19,509	18,265	18,186	18,138	17,280	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490	16,490
Generation Under Construction																			
Conventional	-	-	-	-	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Construction Capacity	-	-	-	-	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Generation Under Development																			
Conventional	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	-	-	33	56	56	56	55	55	55	55	54	54	54	54	53	53
Total Planned Development Capacity	-	-	-	-	-	33	56	56	56	55	55	55	55	54	54	54	54	53	53
Potential (Expected) New Capacity																			
Conventional	-	-	-	-	-	-	-	458	916	1,374	1,832	2,290	2,290	2,290	2,748	3,206	3,664	3,664	3,664
Renewable	-	-	-	-	-	73	163	272	381	472	581	689	798	907	998	1,070	1,089	1,198	1,306
Total Potential New Capacity	-	-	-	-	-	73	163	730	1,297	1,846	2,413	2,979	3,088	3,197	3,746	4,276	4,753	4,862	4,970
Other (NUG)	1,775	1,252	238	346	366	372	372	153	152	152	151	150	149	149	148	147	146	145	144
Unforced Availability	-	-																	
Net Generation Capacity	21,256	20,738	19,747	18,611	20,137	20,201	19,456	19,014	19,580	20,128	20,694	21,259	21,367	21,475	22,023	22,552	23,028	23,134	23,242
Existing DSM Reductions																			
Demand Response	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Conservation/Efficiency	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing DSM Reductions[(1)]	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Approved DSM Reductions																			
Demand Response[(4)]	81	103	70	99	100	100	101	101	102	102	102	102	102	102	102	102	102	102	102
Conservation/Efficiency[(2)(4)]	72	93	109	154	193	202	203	202	204	202	200	198	198	198	198	198	200	201	202
Total Approved DSM Reductions	153	196	179	254	293	302	303	304	305	304	302	300	300	300	300	300	302	303	304
Proposed DSM Reductions																			
Demand Response[(4)]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conservation/Efficiency[(2)]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Proposed DSM Reductions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Demand-Side Reductions[(1)]	155	198	181	255	295	304	305	305	307	305	303	302	301	301	301	302	303	305	306
Net Generation & Demand-side	21,411	20,936	19,927	18,866	20,431	20,505	19,761	19,319	19,887	20,433	20,997	21,561	21,669	21,777	22,324	22,854	23,331	23,439	23,548
Capacity Sale[(3)]	[redacted]								-	-	-	-	-	-	-	-	-	-	-
Capacity Purchase[(3)]	[redacted]								1,100	1,000	800	600	800	900	700	500	300	400	400
Capacity Adjustment[(3)]	[redacted]								-	-	-	-	-	-	-	-	-	-	-
Capacity Requirement or PJM Capacity Obligation	[redacted]								20,965	21,485	21,847	22,214	22,457	22,674	23,005	23,389	23,652	23,839	24,024
Net Utility Capacity Position	[redacted]								(1,078)	(1,052)	(850)	(653)	(789)	(898)	(681)	(535)	(321)	(400)	(476)

(1) Existing DSM programs are included in the load forecast.

(2) Efficiency programs are not part of the Company's calculation of capacity.

(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.

(4) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.

Appendix 6D – Construction Forecast for Plan E: Federal CO_2 Program

Company Name: Virginia Electric and Power Company **Schedule 17**

CONSTRUCTION COST FORECAST (Thousand Dollars)

(PROJECTED)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
I. New Traditional Generating Facilities																
a. Construction Expenditures (non-AFUDC)	60,230	266,162	588,571	714,021	769,626	688,425	611,920	495,641	242,863	338,722	360,618	350,887	208,672	131,133	238,489	296,445
b. AFUDC	153	646	1,962	4,005	5,465	6,843	7,859	8,498	8,522	9,439	10,671	10,808	10,577	4,093	4,721	1,768
c. Annual Total	60,383	266,807	590,533	718,026	775,091	695,269	619,780	504,140	251,385	348,162	371,289	361,695	219,249	135,226	243,210	298,213
d. Cumulative Total	60,383	327,190	917,723	1,635,749	2,410,840	3,106,109	3,725,889	4,230,028	4,481,413	4,829,575	5,200,864	5,562,559	5,781,809	5,917,035	6,160,245	6,458,458
II. New Renewable Generating Facilities																
a. Construction Expenditures (non-AFUDC)	127,903	551,633	748,049	718,976	710,554	594,736	717,332	753,926	768,913	773,491	657,151	525,641	196,119	848,438	890,640	896,006
b. AFUDC	247	1,556	2,232	1,604	1,589	1,323	1,600	1,682	1,715	1,729	1,468	1,182	418	1,896	1,987	2,002
c. Annual Total	128,150	553,190	750,281	720,580	712,142	596,059	718,932	755,608	770,628	775,220	658,619	526,823	196,537	850,334	892,627	898,009
d. Cumulative Total	128,150	681,339	1,431,620	2,152,200	2,864,342	3,460,401	4,179,333	4,934,941	5,705,569	6,480,789	7,139,408	7,666,231	7,862,767	8,713,102	9,605,728	10,503,737
III. Other Facilities																
a. Transmission	777,736	911,890	784,451	784,738	826,874	857,241	836,003	851,548	854,887	847,479	851,305	851,345	851,376	851,342	851,354	851,357
b. Distribution	727,300	770,288	847,930	839,988	852,572	864,130	882,632	886,879	888,080	885,864	886,941	711,941	711,941	711,941	711,941	711,941
c. Energy Conservation & DR																
d. Other																
e. AFUDC	29,130	42,510	36,549	36,262	38,626	42,759	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000
f. Annual Total	1,534,166	1,724,688	1,668,930	1,660,988	1,718,072	1,764,130	1,757,636	1,777,427	1,781,966	1,772,343	1,777,246	1,602,286	1,602,317	1,602,283	1,602,295	1,602,298
g. Cumulative Total	1,534,166	3,258,854	4,927,785	6,588,773	8,306,845	10,070,975	11,828,611	13,606,038	15,388,004	17,160,347	18,937,593	20,539,879	22,142,196	23,744,479	25,346,774	26,949,072
IV. Total Construction Expenditures																
a. Annual	1,722,698	2,544,685	3,009,744	3,099,595	3,205,305	3,055,457	3,096,348	3,037,174	2,803,980	2,895,725	2,807,153	2,490,804	2,018,103	2,587,843	2,738,132	2,798,520
b. Cumulative	1,722,698	4,267,383	7,277,128	10,376,722	13,582,028	16,637,485	19,733,833	22,771,007	25,574,987	28,470,711	31,277,864	33,768,669	35,786,772	38,374,615	41,112,747	43,911,267
V. % of Funds for Total Construction Provided from External Financing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Appendix 6E – Capacity Position for Plan E: Federal CO_2 Program

Company Name Virginia Electric and Power Company **Schedule 4**

POWER SUPPLY DATA

	(ACTUAL)			(PROJECTED)															
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
I. Capability (MW)																			
1. Summer																			
a. Installed Net Dependable Capacity(1)	19,481	19,486	19,509	18,265	19,771	19,828	19,085	18,861	19,428	19,976	20,543	21,109	21,218	21,326	21,875	22,405	22,881	22,990	23,098
b. Positive Interchange Commitments(2)	1,757	1,252	238	346	366	372	372	153	152	152	151	150	149	149	148	147	146	145	144
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response - Existing	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
e. Demand Response - Approved(5)	81	103	70	99	100	100	101	101	102	102	102	102	102	102	102	102	102	102	102
f. Demand Response - Future(5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
g. Capacity Sale(3)	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
h. Capacity Purchase(3)	[redacted]							1,300	1,100	1,000	800	600	800	900	700	500	300	400	400
i. Capacity Adjustment(3)	[redacted]							-	-	-	-	-	-	-	-	-	-	-	-
j. Total Net Summer Capability(4)	[redacted]							20,414	20,780	21,228	21,594	21,960	22,268	22,476	22,823	23,153	23,428	23,635	23,743
2. Winter																			
a. Installed Net Dependable Capacity(1)	-	-	-	19,452	21,052	21,059	20,239	20,039	20,632	21,206	21,798	22,390	22,499	22,608	23,182	23,738	24,240	24,348	24,457
b. Positive Interchange Commitments(2)	-	-	-	350	370	377	376	153	152	152	151	150	149	149	148	147	146	145	144
c. Capability in Cold Reserve/ Reserve Shutdown Status(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d. Demand Response(5)	5	4	5	8	8	9	9	10	11	11	11	11	11	11	11	11	11	11	11
e. Demand Response-Existing(6)	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
f. Total Net Winter Capability(4)	-	-	-	19,810	21,430	21,445	20,624	20,202	20,795	21,368	21,960	22,551	22,659	22,768	23,341	23,896	24,397	24,504	24,612

(1) Net Seasonal Capability.
(2) Includes firm commitments from existing Non-Utility Generation and estimated solar NUGs.
(3) Capacity Sale, Purchase, and Adjustments are used for modeling purposes.
(4) Does not include Cold Reserve Capacity and Behind-the-Meter Generation MWs.
(5) Actual historical data based upon measured and verified EM&V results. Projected values represent modeled DSM firm capacity.
(6) Included in the winter capacity forecast.